INTERIM STAFF MARKET CLEARING PRICE FORECAST FOR THE CALIFORNIA ENERGY MARKET:

Forecast Methodology and Analytical Issues

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This Interim Market Clearing Price (MCP) Forecast is based on an interim forecast of gas prices, developed by the Energy Commission's Fuels Office. The MCP Forecast will be updated if the final FR 97 Gas Price Forecast has significant changes.

Section I provides the Interim MCP Forecast and a brief overview of the assumptions and procedure. Section II provides the assumptions, and Section III describes the procedure used -- this Forecast should not be used for any purpose without carefully reviewing these two sections. Section IV describes the relationship between MCP and marginal cost (MC) in a way that is useful in understanding the competitive market as it relates to the traditional regulated market. It compares the results of UPLAN market model to single-area Elfin production cost runs, and compares both of these to a simplistic market model. It also provides a rule of thumb formula for adjusting the following MCP Forecast for other gas prices. Section V provides personnel whom you can contact regarding questions about the MCP Forecast.

I. MARKET CLEARING PRICE FORECAST

Table 1 presents the Energy Commission Staff's MCP forecast in both nominal (current) and real (constant) 1998 dollars. Figures 1A and 1B summarize this same data in graphical format.

TABLE 1: MCP FORECAST

	MCP ($/MWh)	
YEAR	NOMINAL	1998$
1998	27.2	27.2
1999	25.9	25.3
2000	26.6	25.3
2001	27.3	25.3
2002	29.3	26.3
2003	30.3	26.4
2004	31.6	26.7
2005	32.8	26.8
2006	34.3	27.1
2007	35.7	27.2
2008	37.3	27.4

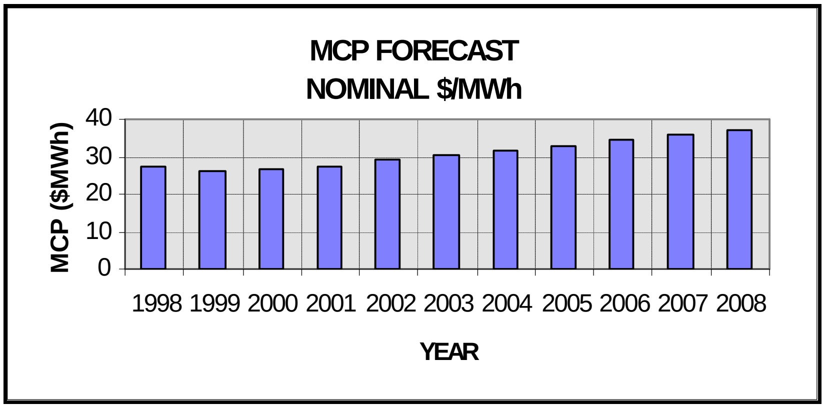

Figure 1A

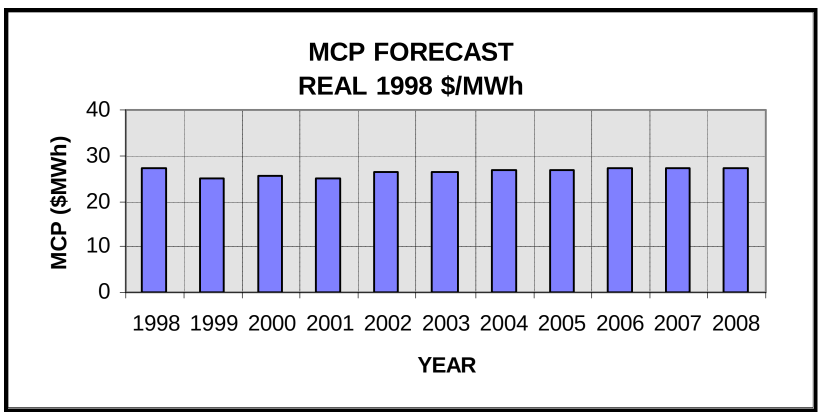

Figure 1B

The MCP in Perspective

Beginning in 1998, the Western Energy Power Exchange (PX) will accept bids from generators in California and out-of-state on an hourly basis to meet the electricity demands of the customers of California's investor-owned utilities (IOUs).[1] The last bid accepted for a particular hour is the price the PX pays all generators for electricity provided in that hour. That price is the seller's market clearing price (MCP).[2] The seller's MCP will also be the energy rate component of most Californian's electricity bills.[3] Some customers, instead of purchasing their electricity from the PX, will obtain their electricity from

1. [1] At this time, California's municipal utilities will not be participating in the PX.
2. [2] The seller's MCP is equal to the buyer's MCP as the generators are required to be responsible for transmission losses.
3. [3] The energy rate for consumers will be the seller's/buyer's MCP adjusted for distribution losses.

generators through individual contracts, alternatively referred to as direct access or bilateral contracts. These contracts may in some cases be indexed to the MCP of the PX. The MCP, therefore, can affect the price direct access customers pay for electricity.

In order to forecast the MCP, Commission staff have been working for the past three years with software vendors on developing a model which would emulate the bidding procedures of the PX and the system dispatch procedures of the newly created Independent System Operator (ISO). The ISO is responsible for ensuring the reliability of the system. As will be explained later, capturing the reliability requirements of the system does have a major influence on the MCP.

In producing this MCP Forecast we have relied on simulations from four different models: LCG's UPLAN Network Power Model, General Electric's MAPS Model, the Environmental Defense Fund's Elfin Model, and the Altos NARE model.[4] We have also relied on the cost of a new entrant to put an upper limit on the MCP.

All of the modeling that has been done in producing this forecast assumes that bids are based on variable operating costs of the generating unit, with two exceptions. We expect that some bidders will under-bid during the off-peak in order to remain on-line, and then over-bid during the on-peak to compensate for their off-peak losses. We expect that they will also attempt to correct for their losses by adjusting their bids upward during periods of high load and low resource availability. We recognize, however, that in a competitive market there will be some companies whose bidding strategies may be much more complicated than this, but we have not attempted to predict such behavior.

As is shown in Table 1, the MCP starts at about 27 $/MWh and then falls in 1999, holds constant in real dollars for three years and then starts to recover in about 2002. It is not until 2007 that it rises to its 1998 level. This pattern reflects the effect of falling natural gas prices, estimated for 1999, when transportation facilities for the vast gas resources of the Gulf of Mexico become available. In real terms, gas prices do not return to their 1998 level until about 2011 - 2012.

From 1998 to 2002 the MCP reflects the results of the UPLAN model. During this period the increased load is met with out-of-state power. After 2002 the MCP is set, outside of the model, to be equal to the price of a new entrant. This is done based on the logic that the MCP will rise in response to increased load but once it is high enough to attract to new entrants, new entrants will come into the market and drive the MCP downward back to its previous level.

Staff's UPLAN modeling assumes that units owned by IOUs or others who are also dependent on the energy market for their total revenue will not bid their incremental costs -- although this is still predicted by some analysts. Bidding at incremental costs -- reflecting incremental heat rates -- would exactly emulate the MC of traditional production cost modeling, and would provide woefully inadequate revenue to survive the market. In support of this position, staff provides extensive explanation in this Forecast to show that MCP should be about 25 percent higher than MC.[5]

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4. [4] These models and their roles in the MCP Forecast are described in Section III of this report.
5. [5] See Section IV, **MCP Compared to MC**.

An important aspect to forecasting the MCP in the early years is the role of must-run reliability contracts with the ISO. To the extent that a generator's costs are recovered through these contracts, they will not have to be recovered from the MCP and the generator can afford to bid at lower levels -- perhaps approaching incremental cost. Staff feels that these must-run contracts are a more cost-effective way to provide the necessary reliability, but continues to have reservations about there being so many of these must-run contracts that they depress the MCP and risk the viability of new entrants.

Staff considers its MCP Forecast to be the minimal level necessary to support a viable market that will attract new entrants. If the MCP falls short of this, then the ISO may very well be in the position of having to attract new entrants using other forms of remuneration such as must-run contracts which seems contrary to the motive of a competitive market.

During the first few months when the market is creating itself, it is to be expected that lower -- or higher -- MCPs may appear in the market as the participants develop their bidding strategies. Staff does not expect, therefore, that its MCP forecast will be manifested immediately but rather over the year.

In all of staff's simulations with the UPLAN model, some generators are consistently unable to recover all of their variable and fixed O&M costs. Most of these same generators have been identified as necessary for the reliability of the system and will most likely receive sufficient remuneration from must-run contracts with the ISO. The remaining units that do not have must-run contracts and do not appear viable without them are the Highgrove and Long Beach plants.

Zonal and Sub-Period MCPs

This MCP Forecast is an annual average for the entire State. We have not provided separate MCPs for the two ISO congestion management zones (Northern California and Southern California), as our experience has shown that forecasting zonal MCPs is not meaningful. Staff has also concluded that the zonal price differences are a complex function of both fuel prices -- most importantly gas prices -- and transmission congestion, in and out-of-state. Our modeling results show that the MCP for the Northern California zone can be either higher or lower than the MCP for the Southern California zone, given the right set of gas price assumptions

Even if there are differences in **inter-zonal** MCP, they will disappear over time. If prices are temporarily higher in one zone, then new entrants will develop for that zone, thus reducing the MCP until it is essentially equal to the other zone. Also, market participants will find other ways to exploit **inter-zonal** price differences, such as arbitraging power. Staff, therefore, has elected to forecast one statewide MCP.

Nevertheless, we provide Table 2 which presents zonal data developed by the UPLAN model, for the 1998 MCPs. Table 2 shows that Northern California can be higher or lower depending on the particular month but averaged over the year the MCP is higher than the Southern California's MCP.[6]

6. [6] MAPS modeling indicates that given uniform gas prices in California, the Northern California MCPs should be about 15 percent higher, but Staff has concluded that this is due to sub-transmission congestion which is not supposed to be reflected in the MCP. This intra-zonal congestion is to be captured as an uplift charge to all customers in the zone,

TABLE 2: 1998 MCPs BY ZONE AND SUB-PERIOD

	NO. CALIFORNIA ZONE NOMINAL MCP ($/MWh)			SO. CALIFORNIA ZONE NOMINAL MCP ($/MWh)		
1998	Off-Peak	On-Peak	Average	Off-Peak	On-Peak	Average
Jan	24.5	31.3	28.7	23.0	33.1	29.3
Feb	18.2	30.3	25.8	17.2	30.8	25.7
Mar	23.8	28.2	26.5	22.5	27.6	25.7
Apr	19.0	24.4	22.4	17.9	24.2	21.8
May	20.7	28.1	25.3	17.2	26.2	22.8
Jun	17.1	29.8	25.0	15.8	26.9	22.8
Jul	25.8	36.4	32.4	22.8	32.2	28.7
Aug	25.0	33.9	30.6	22.0	32.7	28.7
Sep	24.0	31.8	28.9	22.3	31.2	27.9
Oct	24.6	28.4	27.0	23.4	29.9	27.4
Nov	26.3	29.8	28.5	22.7	30.8	27.8
Dec	27.6	33.1	31.0	25.3	35.2	31.5
Annual	23.0	30.5	27.7	21.0	30.1	26.7

These monthly variations are a function of monthly gas prices and monthly variation in transmission congestion, that averaged over a year show the Northern California zone to have slightly higher MCPs.

The monthly values in Table 2 are shown by subperiod. On-peak is defined as 8 AM to 10 PM. off-peak is defined as 10 PM to 8 AM. The on-peak is much higher than the off-peak costs due in part to the participants bidding lower in the evening in order to stay on line. Staff expects that the ratio of on-peak to off-peak could even be higher than shown here due to generators taking advantage of capacity shortage opportunities in the on-peak periods that are not completely captured by the UPLAN model – as well as by lower bidding than the levels assumed in the modeling during the off-peak periods.

which is then distributed amongst the generators who had to adjust their generation. The NARE model, which has only transport generation, also shows MCPs differences similar to MAPS.

II. ASSUMPTIONS

All forecasts are driven by the assumptions therein. It is important, therefore, to understand the assumptions inherent in any forecast before using it for any purpose. Nowhere is this more true than with MCP forecasts. The multitude of factors and the complex nature of the factors that drive the MCP make it even more vulnerable to its assumptions than its predecessor, the production cost forecast.

The traditional production cost forecast relies on the difficult, but nevertheless relatively straight forward, task of forecasting loads and resources; this requires that the loads be characterized both in terms of magnitude and load shape, and the resources be characterized in terms of magnitude, generation profile, efficiency (heat rates), fuel type, fuel cost, emissions, and availability (maintenance requirements and probability of forced-outages). In addition, the non-economic generation and transmission constraints must be adequately characterized. These include commitment, spinning reserve and must-run requirements (voltage support and local area generation requirements). If the model is a chronological model, then time constraint data are also required: ramp-rates, and warm-up times and warm-up costs (both for cold-starts and warm-starts). If the model is capable of emulating transmission, then the transmission must be characterized to represent power flow limits, transmission losses and transmission constraints. If the model is not capable of directly emulating transmission -- as is more typically the case -- then the effects of transmission must be emulated indirectly through setting limits on the actual power quantities available in the resource emulation. In addition, capacity expansion is typically required so the fixed cost components also have to be characterized. These included the capital costs, fixed O&M costs and all the economic variables necessary to characterize these costs, such as cost of capital, fixed charge rates and capital recovery factors. As difficult and uncertain as this is -- typically requiring uncertainty analysis -- or at least scenarios -- it is still much more straight forward than the task of characterizing the restructured market.

Modeling the restructured market requires all of the data required for the production cost forecast and more. Rather than single utility representations, as is most typically done in the regulated market, modeling of the competitive market requires the characterization of large geographical areas, including the transmission thereof. In the case of the California market, this requires the characterization of the entire WSCC -- which requires obtaining and modeling data for both generation and transmission facilities.

Even more challenging, modeling the competitive market requires the characterization of complex factors, which are not yet entirely understood and therefore essentially unpredictable. The most formidable of these is human behavior. On what basis will the participants bid? What costs will they bid -- or will they even bid based on costs? Will some participants be able to -- and elect to -- exert market power? In what way will they exert that market power? During what time periods? How many bilateral contracts, must-run contracts and ancillary payments will there be? How will these and other sources of revenue affect the ability of participants to modify their bids and thereby affect the MCP? What effect will demand bidding have on the MCP? How will non-member participants modify their bidding for the new market? When will divestiture be complete and what will the new owners do with these units -- and when? Will some of these units be removed from the California market? Which units will be retired and which units will be repowered? Will new owners be able to successfully reduce fixed O&M costs? What effect will consumer behavior have on electricity consumption and therefore on MCP? What consumer options will be offered by the power providers that might change the nature of power consumption? Will there be time-of-day pricing? How soon will the development of new technologies take place and how dramatic will those changes in efficiency be? Will power plant costs be successfully reduced as predicted by many analysts? Who will be the members and who will be the non-member players in the new market and how will their strategies interact?

Perhaps the single most important set of questions to be answered are: how many must-run agreements will be executed, what will be the remuneration and how will this affect the bidding into the market? Even though an interim list has been established, it is not clear what percentage of the time the ISO will restrain the market operation of the unit -- with the possible exception of the C type contracts which are under the complete control of the ISO. It is probable that the list will be modified over time. It is not known to what extent must-run contract remuneration will affect the bids of these units. This single factor can account for many dollars per megawatt-hour in the market clearing price.

The assumptions used herein in regard to both the traditional production cost modeling and the new market modeling are delineated below.

The assumed gas prices are attached as Appendix A, and represent the Energy Commission Fuels Office Interim FR 97 November 17, 1997 Forecast. Questions about the gas price forecast should be addressed to Bill Wood (Phone numbers, FAX numbers and EMAIL addresses are available in Section V). The FR 97 gas prices are based on pre-divestiture ownership -- as are all the assumptions in this MCP. The gas prices are significantly lower than those of FR 95, and contributory to the Staff MCP Forecast that is significantly lower than that of the October 1996 LCG Report[7] which had estimated that the 1998 MCP would be 29 - 30 $/MWh, Northern and Southern California, respectively.[8] The associated general escalation forecast that was used is also included in the Appendix.

The assumed loads are based on the Energy Commission's ER 96 load forecast. Questions about the ER 96 load forecast should be directed to Mike Jaske. For an electronic copy of the UPLAN loads, contact Richard Grix. For Elfin loads and load shapes contact the respective Elfin modeler. Again, refer to Section 5 for phone numbers, FAX numbers and EMAIL addresses.

The UPLAN load shapes and transmission representation are essentially as delineated in LCG's October 1996 Report. The resource data has been modified to add a few resources, increase the number of capacity blocks, and to add a number of non-economic constraints including ramp-rates, warm-up costs & times (both for cold-starts and warm-starts). All of the UPLAN model data can be provided in Microsoft ACCESS data base format from Manuel Ramirez.

This MCP Forecast assumes a normalized year. That is, the weather pattern and hydro availability are assumed to be average.

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7. [7] Modeling the Competitive Energy Market in California: Analysis of Restructuring, dated October 1996. Prepared by Rajat K. Deb, Richard S. Albert and Lie-Long Hsue of LCG Consulting, available at the Energy Commission's Internet Site: http://www.energy.ca.gov/energy.
8. [8] Also contributing to the decrease in MCP from the October 1996 report is the change from 3-Part bidding to 1-Part bidding.

This MCP forecast ignores most of the complexities of human behavior and assumes that the market members[9] will essentially bid based on their variable costs -- but will at times bid in excess of their costs where the opportunity presents itself as explained below. It is also assumed that the market members will under-bid during the off-peak hours in order to remain on line, and then over-bid during the on-peak hours in order to offset the off-peak losses.

The variable costs include both variable O&M and fuel costs. Fuel costs are based on their **average** energy costs (average heat rate as opposed to incremental heat rate) plus start-up fuel cost. It is also assumed that the average energy costs will be based on the total price of gas and not just the dispatch price of gas -- the total cost is equal to the dispatch (commodity) cost plus the transportation (fixed) cost. The assumption of bidding based on total gas is arguable and critical to the MCP magnitudes, but is based on the belief that revenues will be woefully inadequate otherwise.

At the same time, this forecast assumes that non-ISO members will bid based on their incremental costs, which means that they will bid both their fuel and variable O&M based on their **incremental** costs (incremental heat rate as opposed to average heat rate and dispatch price of gas as opposed to total price of gas). This difference in bidding between the member and non-member participants is based on the assumption that members must recover all of their costs from the market, but non-members need only recover their incremental costs (the cost of that increment of power that they are bidding). Non-member participants can bid at this lower cost since they will have already recovered the costs of the other increments of generation elsewhere -- whether it be through regulated rate recovery or sales transaction.

This forecast assumes no significant market power, consistent with FERC and PUC guidelines, but at the same time recognizes that some participants may very well be able to control the MCP during some limited times of the year such as the fall when the availability of northwest power is limited. This behavior may be akin to market power but is not necessarily an abuse, as this limited control of the MCP might very well be necessary to compensate for losses during other periods, and may in fact be necessary for economic survival.

Similarly, there will be comparable "reliability adjustments" to the MCP during the year where bids momentarily rise above those that reflect variable costs. During those periods of high demand, typically a hot summer day or cold winter day, the demand may start to exceed available resources, due in part to limited availability of resources being unavailable due to a combination of maintenance and forced-outages. This should be somewhat aggravated by the fact that maintenance will no longer be under the control of a relatively few providers. Regardless of the ISO's efforts to coordinate resource availability, we can expect some periods of lumpiness in maintenance.

It is also assumed in this forecast that these periods of "reliability adjustments" will become more frequent as loads increase and reserve margins decrease, until that time that new resources enter the market. It is also assumed that in the post 2001 period, when reserve margins become less adequate, that

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9. [9] The terminology "members" is used to represent any participant who will rely on bidding market revenues for all of the remuneration for its plant. For this report, which is based on pre-divestiture assumptions, this is limited to the California IOU units.

the MCP will start to rise, and that by about 2003 it will be sufficient to attract new entrants at a cost of about 26.4 $/MWh (1998$).

This estimated cost of a new entrant reflects the perceived cost of a new entrant by the entrepreneurs and does not reflect the Energy Commission's best estimates. Staff believes that the developers are overestimating the probable capacity factors and underestimating the capital and fixed O&M costs. Staff accepts the 28 $/MWh estimate (for 1998) as a basis for the MCP Forecast in contradiction to its own best estimates in deference to the fact that those spending the money are entitled to their own perceptions regardless of Staff's opinion. Staff also accepts the fact that these estimate may in fact be realized in the competitive market, similar to that of previous competitive markets. The economics of new entrants is covered in detail in Appendix B.

Between 1998 and 2002, the additional load will be served by out-of-state power -- planned additions. After 2002 it is assumed that the MCP will remain essentially at the cost of new entrants, as each time the MCP achieves this level a new entrant will come into the market resetting the MCP to its former level.

There are no other assumptions regarding the effects of human behavior, conservation, or time-of-day pricing other than those that are inherent in the demand forecast, or as mentioned above.

This MCP Forecast assumes that all IOU Combustion Turbines (CTs) will have type C must-run contracts, and will not be allowed to set the MCP. The Forecast assumes that the slow-start units shown in Table 3 will have type A or B contracts and will be allowed to set the MCP when not dedicated to the ISO for reliability dispatch.

TABLE 3: TYPE A & B MUST-RUN CONTRACTS

PG&E	SCE	SDG&E
Contra Costa 6 & 7	Alamitos 1 - 6	Encina 1 - 5
Humboldt 1 & 2	El Segundo 1 - 4	South Bay 1 - 4
Hunters Point 2 - 4	Etiwanda 1 - 4	
Moss Landing 6 & 7	Huntington Beach 1 & 2	
Pittsburg 1 - 7	Mandalay 1& 2	
Potrero 3	Redondo 5 - 8	

III. PROCEDURE

The procedure for this Market Clearing Price (MCP) forecast and analysis did not rely entirely on any one computer simulation -- and in fact did not rely entirely on computer simulations. A forecast of MCP involves so many variables and so many unknowns that reliance on a single computer model does not seem prudent at this time. At the same time, the MCP and supporting analyses are the result of many computer simulations as well as extensive numerical analysis.

The UPLAN model was used to estimate the MCP for the early years of the MCP Forecast: 1998 - 2003. Beyond this point, the cost of a new entrant was used to set the MCP.

Numerous UPLAN simulations were made to bracket both the MCP and find an acceptable level of revenue losses for the market participants. Beyond this, various computer simulations were made with the Elfin, the MAPS and the NARE models as well as spreadsheet calculations to confirm the reasonableness of the assumptions used.

Summary of Computer Models

The following is a list of models presently under lease to the Energy Commission that were used in some way in order to develop this MCP:

- UPLAN - A multi-area chronological generation and transmission production cost and market model owned by LCG Consulting of Los Altos California. Contact Dr. Rajat K. Deb, Richard S. Albert or Lie-Long Hsue at 4962 El Camino Real, Suite 112, Los Altos, CA 94002; Phone (415) 962-9670, FAX at (415) 962-9615, or EMAIL addresses are deb, rich or llh@energyonline.com.
- Elfin - A probabilistic single-area production cost and market model, owned by the Environmental Defense Fund (EDF) of Oakland. This model is under development to be a multi-area model with transport transmission. Contact is Dan Kirshner at 5655 College Avenue, Suite 304, Oakland, CA 94618; Phone (510) 658-8008, FAX (510) 658-0630 or EMAIL elfin@edf.org.
- MAPS - A multi-area chronological generation and transmission model, owned by General Electric (GE). Contact Rana Mukerji or Gary Jordon at Power Systems Energy Consulting, General Electric Company; 1 River Road, Bldg. 2-540; Schenectady, NY 12345; Phone (518) 385-9336 (Rana) or (518) 385-2640 (Gary), FAX (518) 385-3165 or EMAIL mukerja or jordanja@psedmail.sch.ge.com.
- NARE[10] - North American Regional Electricity Model - A multi-area generation and transmission model owned by Altos Management Partners Inc. of San Jose Jet Center. Contact Dale M. Nesbit, Richard White or Michael C. Blaha at 1250 Aviation Drive, Suite 250T, San Jose, CA 95110; Phone (408) 275-0789 or FAX: (408) 275-0799.

1. The UPLAN model was the primary source of MCPs for the 1998 - 2003 MCPs, as well as a reference point for the post 2003 MCPs. UPLAN was also used to develop the 1998 nodal prices (NPs) and MCPs used for Section IV, as well as

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10. [10] This acronym is Energy Commission Staff's characterization of this model. This model is an integrated gas and electric model. Of these two modules, the gas model, NARG model, is the better known model. NARG stands for North American Regional Gas. Staff has thus extrapolated NARG to NARE, North American Regional Electricity Model. The official Altos name is Multi-Regional North American Electricity Model.

NPs for cross referencing with MAPs. The Elfin model was used to develop marginal costs (MCs) as benchmark values for Section IV. The MAPS model was used to validate UPLAN transmission flows and the relative magnitudes of its nodal prices. It was also used to estimate the effect of centralized commitment and dispatch under restructuring as well as to estimate the maximum power flows into California. The Altos NARE Model was used to benchmark the MCP and flows under restructuring by scaling up MCPs of simulations done by Altos to match FR 97 Gas Prices.

UPLAN Procedure

The UPLAN model was used as a simulation of the WSCC using approximately 330 power plants and a network equivalent circuit with 15 demand areas, 87 nodes and 219 transmission lines. The transmission emulation is actual AC load flow, as opposed to DC or transport emulation. The model was run with typical weeks for each month of the year in the chronological mode. The model has various bidding modules which were evaluated but the analysis relies primarily on its 1-Part Bidding (simple-bid) module. The following describes the implementation of this module to develop the MCPs.

The UPLAN model allows all must-run type A and B units to set the market clearing price when not called by the ISO but does not allow a type C unit (CTs) to set the market clearing price.

The modeling in UPLAN requires the market members (California IOU) slow-start units -- whether divested or not -- to bid their variable costs. The variable costs include both variable O&M and fuel costs. Fuel costs include energy based on the unit's **average** costs (average heat rate as opposed to incremental heat rate) and start-up fuel cost. These same units bid based on the total price of gas, not the dispatch price of gas. Units are allowed to bid above average costs where this increases the revenue to the unit.

The market participants are required to bid each unit (or group of units) monotonically; that is, the price must increase with each subsequent capacity block. For the market member who must capture their entire revenue from the market, the unit is constrained by the fact that its costs decrease with each subsequent block. The modeling of this paradox requires that the exact capacity level of the unit be known for each hour of operation in order to offer a bid truly reflecting the unit's costs. This requires a modeling solution that either iterates to that point -- all too time consuming -- or is based on a good guess. The procedure used for this MCP Forecast does the latter by having the modeler adjust individual bids based on learned knowledge of typical heat rates. At the same time, this modeler recognizes that the bidding behavior will be such that the bids should be less than this during off-peak hours (to guarantee operation) but more than this during on-peak hours to compensate for loss of revenue during the off-peak hours. The UPLAN model has options that facilitate this on-peak to off-peak bidding behavior.

The treatment of non-ISO member market participants is entirely different. The UPLAN modeling requires that non-members will continue to operate as in the past and bid based on their **incremental** costs, which means that they will bid their fuel cost based on incremental heat rate and dispatch price of gas plus variable O&M costs. This difference in bidding between the member and non-member participants is based on the assumption that members (IOUs) must recover all of their costs from the market, but non-members need only recover their incremental costs (the cost of that increment of power that they are bidding). Non-member participants can bid at this lower cost since they will have already recovered the costs of the previous increments of generation elsewhere -- whether it be through regulatory rate recovery or sales transactions.

The UPLAN modeling does not attempt to emulate market power, even though it is thought that this may very well be possible at least during some periods of some months of the year -- for example, in September when out-of-state resources are less plentiful or when unexpected equipment failures (forced outages) occur in conjunction with high demands. But this is not considered to be market power as it is limited in opportunity and essential to gain the revenue that is necessary for the viability of the unit.

Elfin Procedure

The Elfin model is a single-area production cost model and market model, without transmission emulation. It is capable of capacity expansion in both the market and non-market mode. It is being revised to a multi-area transmission model, but this feature is not currently available.

The Elfin model can not yet provide a MCP directly. It provides an initial MCP based on incremental cost and calculates a commit payment that is a lump sum payment to each unit not actually reflected in the MCP. In this respect, it is analogous to the ISO's must run payments. The model is also limited for applications that require hourly MCPs in that it is a load duration curve model that can only provide yearly, monthly or subperiod MCPs.

The model was used as a single-area model without transmission to provide 1998 baseline reference marginal costs (MCs) for Section IV.

MAPS Procedure

The MAPS model is a multi-area generation and transmission model with 837 generating units, 4,345 buses and 1,115 transmission lines. The complexity of this model makes it uniquely useful for studying transmission flows but burdensome for modeling.

The Energy Commission is presently limited in that it is using a 1995 data set which is used to approximate the market flows. It has been benchmarked against the UPLAN model, but the difference in the nature of the models combined by the immensity of their sizes must always engender reservations about their exact relationship. The model is also limited by its inability to emulate bidding based on cost. The MAPS model can accept bids but cannot construct bids.

The MAPs model was run using the 1995 data set against 1998 UPLAN data to ensure that the flows are reasonably similar. The MAPS model dispatches based on incremental cost. Whereas the UPLAN model runs based on one-part bidding, which is emulating average cost for market members. This difference was offset on some simulations by using the 3-Part bidding option of UPLAN, which dispatches all units based on incremental cost.

IV. MCP COMPARED TO MC

One way to gain insight into the market clearing price (MCP) is to view it from the perspective of marginal cost (MC), as MC is a system measurement with which analysts are already familiar. Anyone who has participated in an electricity price forecast is familiar with MC as a parameter of production cost modeling. In production cost modeling, MC is the cost of the last increment of power used to meet load.

The MCP is analogous to MC in that both provide the cost basis for dispatch. In the regulated system MC is the cost of the least expensive block of power available to meet the final increment of load in that hour. In the market the MCP is the cost of the least expensive bid offered to meet the final increment of load in that hour. If the market participants were to bid based solely on their incremental costs -- as some analysts argue -- the MCP would be identical to MC. But it is not -- and why it is not is the purpose of this section.

This comparison of MCP to MC is done herein in two ways: first, by comparing the UPLAN model results used in this Forecast to single-area Elfin runs; and second by using a simplistic market model developed by staff.

Comparing UPLAN's MCP to Elfin's MC

Elfin is the model that staff has used for many years to analyze the regulated market and do electricity price forecasts. It is a single-area (one utility at a time) production cost model with no transmission representation. UPLAN is the new multi-area model that staff is using to analyze the new market. It is a multi-area model that emulates the generation and transmission facilities of all the utilities participating in the new market (i.e., the WSCC).

Table 4 provides a summary of relevant MCs of Elfin production cost simulations, as well as nodal prices (NPs) and market clearing prices (MCPs) taken from actual UPLAN market modeling simulations. All values in this table reflect the assumptions and procedures used in this MCP Forecast, which are delineated in the section II and III, respectively.

Row-1 in Table 4 summarizes MCs from Elfin production cost runs for the three IOUs: PG&E, SCE and SDG&E. Each IOU is modeled separately as a single-area production cost simulation without transmission representation. Off-system purchases are represented -- as is typical of a single- area production cost simulations -- as simplified aggregations of contracts and non-firm energy. The MCs are based on the dispatch price of gas (DGP). The "Average" MC is calculated as a weighted average of the single-area MCs, based on the energy generation of the slow-start units, which in general tend to set the MC -- this is admittedly simplistic but can be shown to be reasonably adequate (Appendix C).

TABLE 4: COMPARISON MCs, NODAL PRICES AND MCPs FOR 1998

ROW	FORECAST YEAR = 1998 GAS PRICES = INTERIM FR 97	PG&E[11] ($/MWh)	SCE ($/MWh)	SDG&E ($/MWh)	AVERAGE ($/MWh)
1	Elfin MC - DGP	19.2	22.0	22.0	20.8
2	Elfin MC - TGP	21.9	22.3	25.1	22.3
3	UPLAN NP - TGP MC from 3-Part Bids	26.1	24.8	25.4	25.4
4	UPLAN NP - TGP With Start-Ups	27.9	25.4	26.1	26.5
5	UPLAN NP - TGP with Simple Bids	26.9	25.5	25.9	26.1

	FORECAST YEAR = 1998 GAS PRICES = INTERIM FR 97	NORTHERN CALIFORNIA	SOUTHERN CALIFORNIA	AVERAGE
6	MCP - TGP with Simple Bids ($/MWh)	27.7	26.7	27.2

DGP = Dispatch Gas Price TGP = Total Gas Price

Row-2 in Table 4 is the same as in first row with the singular exception that the total gas price (TGP) is used for all of the California IOU gas-fired units, instead of the dispatch gas price (DGP) -- non-IOU units do not change their fuel prices. This difference is considered relevant to the MCP as it is expected that the market members (IOUs and those units dependent solely on the market for revenue) will have to bid based on the total price of gas, or their bids will be hopelessly inadequate to obtain sufficient revenue. This assumption is arguable but nevertheless accepted by many analysts and is an assumption used throughout this analysis. SCE MCs change only slightly as SCE's total gas price is equal to its dispatch price except for the Cool Water units. PG&E and SDG&E change by about 14 percent so that overall the IOU system changes by about 7 percent.

Row-3 presents the corresponding values from the UPLAN multi-area generation and transmission model.[12] At this point, MC is replaced with the nodal price (NP) which is the corresponding concept in a model that incorporates transmission. The single-area model having no transmission has a singular node with a singular nodal price which is characterized as MC. The multi-area model has many MCs which are called NPs. The change in value from the MC price in Elfin to the nodal price in UPLAN represents the effect of three things. First, it represents the effect of directly representing transmission. This includes the various effects of the electrical parameters of the transmission lines: transmission losses, transmission congestion and the effect on power flow. Second, it represents the effect of improved modeling. Whereas single-area models are only approximating the inter-utility interaction, the multi-area model is

11. [11] In the UPLAN modeling, PG&E is represented by four load nodes: Humboldt, San Francisco, PG&E in Zone 3 (70%) and PG&E in Zone 4 (30%). The NP in Table 4 is the simple average of these four nodes.
12. [12] This data is taken from the 3-Part bidding module of the UPLAN market model. This particular module in UPLAN emulates the earlier envisioned 3-Part bidding mechanism which WEPEX has subsequently abandoned, and is therefore no longer directly relevant to the California market. Nevertheless, this module is useful in that it calculates MC based on the incremental dispatch of traditional production cost modeling, prior to the end of day adjustment that creates the actual MCP.

representing this dynamic interaction directly. Third, it represents the increased efficiency of the California market bringing the three IOUs under one control center. Staff has quantified this last effect as being surprisingly small[13] so that the first two factors are more important.

The exact relationships are complex and do not lend themselves to simple explanations, but it would appear that at least two explanations can be offered. PG&E shows the highest percentage increase as a reflection of congestion, part of which is due to the limited adequacy of its transmission lines. Also, it now shares its lower cost power with the other two IOUs more equitably. SDG&E changes the least as it has reasonably low congestion to its southwest resources, for which it relies on for much of its power. Also, it is now taking advantage of the other IOUs low cost power. SCE falls in the center due largely to its better built transmission system

Row-4 presents the same values in row-3 with the singular exception that start-up costs are included in the NP. This data is produced as an option in the UPLAN model. The effect of start-ups appears to be small: of the order of 2 - 7 percent depending on the node.

Row-5 shows a NP that reflects the single-part bid rather than true nodal cost prices. These NPs are similar to row-4 except that the NPs are produced by the 1-part bidding values. CTs and start-up costs are allowed to contribute to the NP. In general, the 1-part bidding values are generally representative of average heat rates for the market members and the incremental heat rates for the non-market members units -- exceptions are made where the unit maintains a must-run contract with the ISO who may very well elect to dispatch units under its control using traditional least cost dispatch.

The MCPs are produced by the UPLAN model based on 1-Part bids that reflect the IOU units bidding their average heat rates, the total gas price (TGP) and start-up costs -- but not the costs of combustion turbines as they are considered to be on type C must-run contracts with the ISO and as such can not set the MCP.

The "Average" values suggest that the ratio of MCP to MC is equal to about 1.26 (27.2/20.8 = 1.26). That is, the MCP is about 30 percent higher than the MC we know from single-area Elfin simulations.

A Simplistic Market Model

The MCP can also be compared to MC using a simplistic model developed by staff. This model is not intended to be accurate but rather is designed to be illustrative of the workings of the new market as it compares to the present regulated systems. This technique is based solely on the same block heat rate data used in the Elfin/UPLAN models and 1998 gas prices. The calculations and methodology are provided in Appendix C or those who would like to replicate this process.

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13. [13] Energy Commission Staff have quantified this in MAPs and found that this effect on NP is of the order one-half of one percent. Although one would off-hand expect this to be greater, the effect of centralized commitment and dispatch is greatly mitigated by the need for must-run generation for reliability purposes, as evidenced by the large number of must-run contracts that have been identified to date.

Traditional production cost modeling consists of commitment and dispatch. The commitment process consists of identifying the most economic set of plants necessary to meet the daily peak. The dispatch of these plants is based on the incremental cost of each plant's capacity blocks. The incremental cost is determined by the fuel cost (the incremental heat rate times dispatch gas price) plus variable O&M, on a $/MWh basis. The capacity block with the least incremental cost at the moment of increased load is dispatched to meet that load.

In the California market, the ISO disavows responsibility for commitment and assigns that responsibility to the bidder. The dispatch is based on the lowest bid offered. For the case of non-members, who have other means of capturing revenue and are just offering increments of surplus power to the market, their bids will probably continue to be based on their incremental costs. But for the members of the market (IOUs and those who will depend on the market for all their revenue), their bids must reflect all costs, not just incremental costs. Their variable O&M costs will not change, but their fuel bid must now reflect their average cost (average heat rate times total gas price) as well as their start-up costs.

Staff's simplistic model ignores the effects of variable O&M and start-up costs, as well as the effects of commitment. It concentrates solely on the differences in heat rates between the MCP and MC. This difference in heat rates is illustrated in Figures 2A, B & C which compare the incremental heat rates (***IHR***) of traditional dispatch (MC) to the average heat rates (***AHR***) relevant to MCP. The heat rate curves are for the slow-start gas-fired units, only, under the assumption that these units will set the market clearing price most of the time -- although this is only approximately true.[14] The heat rate curves are shown separately for each IOU in order to make the presentation more legible. In actual practice, the three curves would be combined -- and would include all units and not just the slow-start gas-fired units.

The process for deriving the incremental heat rate (***IHR***) curves of the Figure 2 series are as follows. Each slow-start gas-fired unit is represented by four ***IHR*** blocks, which are taken from the average heat rate data provided in the ER 96 CFM filing and used in the Elfin and UPLAN models.[15] In cases where two units have the same size capacity blocks, they are combined into one equivalent unit in order to make the computation and representation simpler. These heat rate blocks are then sorted by increasing ***IHRs*** as shown in the Figure 2 series.

The average heat rate (***AHR***) blocks are derived in a similar fashion except that they must be adjusted for the fact that they are not an average value <u>for the block</u>, as is the ***IHR***. They are the average heat rate at the <u>end of the block</u>. The corresponding average-average heat rate was developed using calculus (Appendix C) and is designated as AHR_{AVE} in this MCP forecast to differentiate it from the normal ***AHR*** of the UPLAN/Elfin models and CFM data.

14. [14] Various simulations suggest that the slow-start gas-fired IOU units will only set the market clearing price approximately 50 to 70 percent of the time, depending on the particular set of assumptions.
15. [15] The CFM filing provides five blocks of average heat rate data but the first block does not qualify as an incremental heat rate. It is an average heat rate.

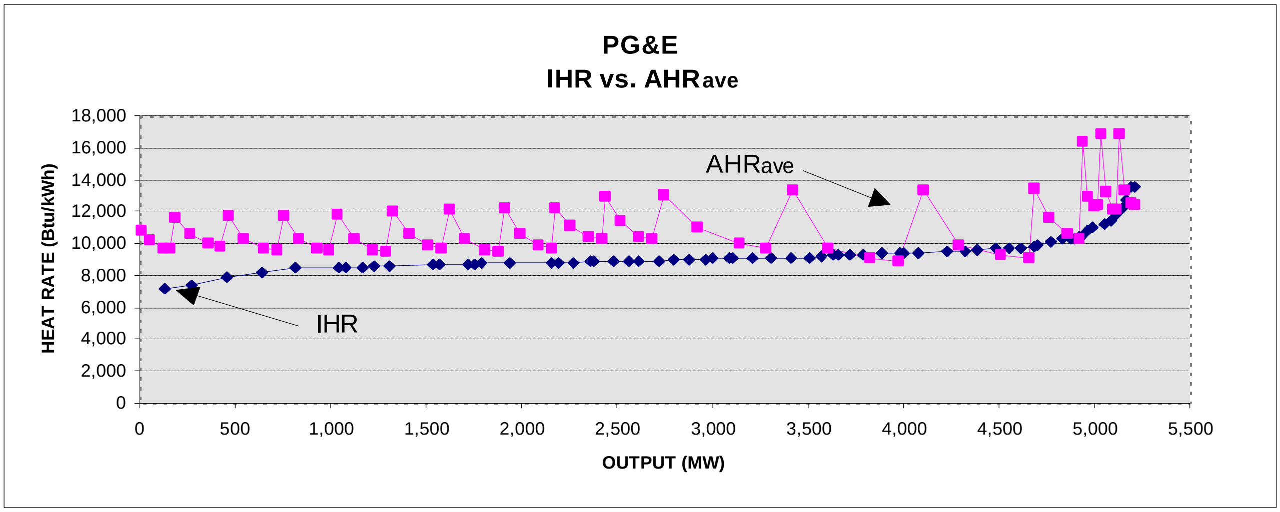


Figure 2A

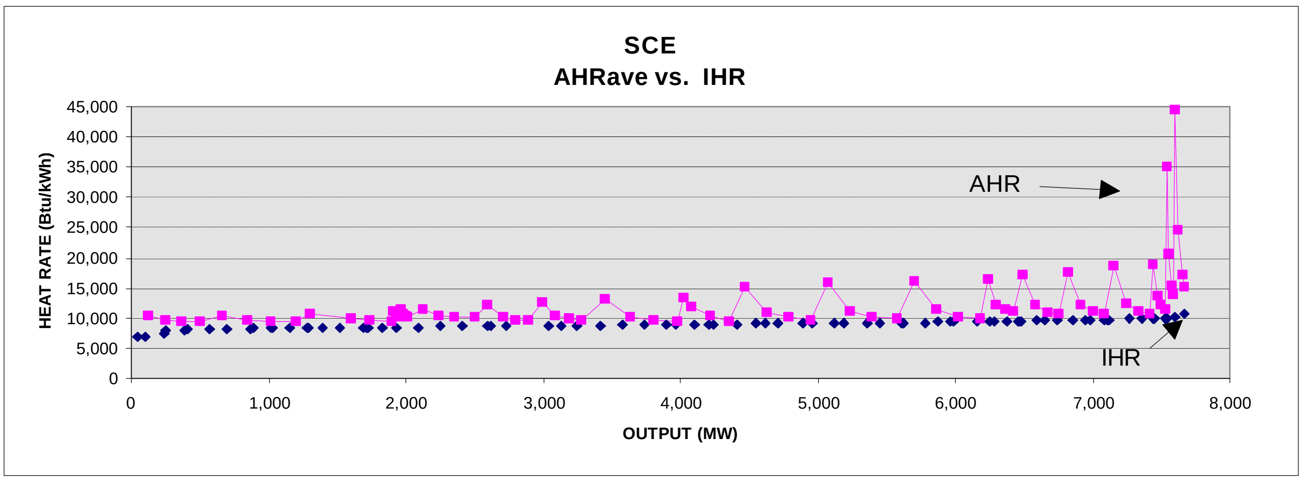


Figure 2B

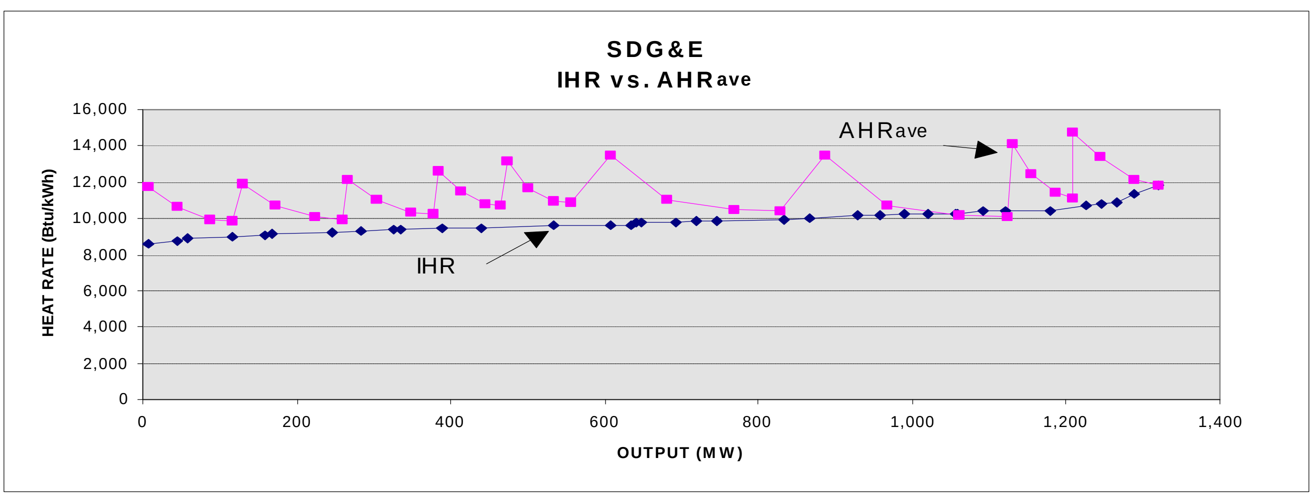


Figure 2C

In emulating dispatch, the $\boldsymbol{AHR_{AVE}}$ blocks can not simply be ordered by increasing heat rate. This would lead to the physical impossibility of a less expensive upper block being dispatched before a more expensive lower block. To represent this physical limitation, the units are first sorted based on their first block heat rates. When the first unit with the lowest first block heat rate is identified, it is logical that all of its upper blocks will then be dispatched before going on to the first block of any other unit; as at that point, no other unit's first block can compete with this unit's upper blocks. Thus, we see the saw-tooth nature of the $\boldsymbol{AHR_{AVE}}$ curves in the Figure 2 series. The downward sloping arc of each "tooth" represents the average heat rate curve of that unit, starting at the highest heat rate block (first block) and ending at the minimum point (last block).

This $\boldsymbol{AHR_{AVE}}$ curves can not be representative of the California market, as the market requires 1-Part monotonic bidding, such that each unit's bid price series must increase with each block of power. That is, the $\boldsymbol{AHR_{AVE}}$ must look similar to the ***IHR*** curve. The knowledge of this paradox allows us to understand the dilemma of the plant owner in bidding a unit's costs into the market -- or the modeler in modeling the market. Each unit has declining (downward sloping) costs that must be converted to monotonically increasing (upward sloping) costs. These curves can be equal at one point, only. This means that if the plant owner wants to bid its unit's costs in any one hour, the exact generation level -- that one point where the curves are equal -- must be known. Herein lies the difficulty for the plant owner -- and the modeler. If the exact capacity level (block heat rate) can be determined, the correct unit is dispatched. Otherwise, the incorrect unit is selected resulting in inefficient dispatch and the concomitant shift in revenues to an alternative bidder.

The two curves of Figure series 2 illustrate the fact that the $\boldsymbol{AHR_{AVE}}$ dispatch is inherently more costly than the ***IHR*** dispatch -- without even accounting for the difference between the dispatch price of gas and the total price of gas. We can also see from these same figures that the $\boldsymbol{AHR_{AVE}}$ curve is not flat, as is the ***IHR*** curve. This suggests that the typical statements about there not being much variance in the MCP bids between units is perhaps too simplistic.

Some additional insight can be gained by rearranging this data into weighted averages. The Figure 3 series uses the same data of the Figure 2 series except that it is a running weighted average -- as each unit is added, a weighted system average is calculated based on the capacity (MW) of the blocks. This is done for both the ***IHR*** and the $\boldsymbol{AHR_{AVE}}$ data. The respective curves are system values of ***IHR*** and the $\boldsymbol{AHR_{AVE}}$, and are designated ***SIHR*** and the $\boldsymbol{SAHR_{AVE}}$, respectively.

The weighted average data shown in the Figure 3 series can be considered as representative of an average value that could be expected over time. For example, if one selects the final point on each curve, this can be considered as an average value for a period, of say one year, where each generation level has been maintained an equal percentage of the time. This roughly approximates what happens over time, but can never be exactly true.

In order to continue to complete our simplistic model, we accept the last point in the curve as the applicable point for our representation of MC and MCP, which says in fact that all units in the system are considered to be equal players. Although this is unlikely at best, we note the flatness of the curves meaning that these average values do not change appreciatively toward the end of the curve anyway. We can then construct Table 5 which summarizes the heat rate data for the last point in each curve.

TABLE 5: SUMMARY OF SYSTEM HEAT RATES

	PG&E	SCE	SDG&E	AVERAGE
SIHR HEAT RATE (Btu/kWh)	9,052	8,943	9,843	9,067
SAHR HEAT RATE (Btu/kWh)	10,495	11,217	11,081	10,939
$SAHR_{AVE}$ / ***SIHR***	1.16	1.25	1.13	1.21

This data shows the differences between ***SIHR*** and $SAHR_{AVE}$, and indicates that these differences between MC and MCP just due to the heat rate differential are significant. These differences indicate that on average this heat rate difference will cause PG&E's and SDG&E's MCP bids will have to be 16 and 13 percent higher, respectively, than traditional MCs to cover the heat rate differential alone. SCE stands out as having to set its average MCP bid value at 25 percent higher. The system average MCP as 21 percent higher.

This same data also suggests that units will have a different competitive status under the restructured market than they do now. For example, under regulation and traditional dispatch (***IHR***), the SCE units would seem to have the most favorable position -- absent consideration of gas prices -- since SCE has the lowest ***SHIR*** (8,943 Btu/kWh). But based on the market dispatch (AHR_{AVE}), PG&E would appear to have the most favorable position -- since PG&E has the lowest $SAHR_{AVE}$ (10,495 Btu/kWh).

This heat rate analysis is deficient in that it ignores the effect of the gas price. Table 6 summarizes 1998 gas prices, which allows us to further complete our model.

TABLE 6: SUMMARY OF 1998 GAS PRICES (FR 97 - 11/17/97)

FORECAST YEAR = 1998	DISPATCH ($/MMBtu)	TOTAL ($/MMBtu)
PG&E	2.03	2.50
Cool Water	1.67	2.11
SCE OTHER	2.58	2.58
SCE + Cool Water	2.45	2.45
SDG&E	2.22	2.86

Figures 4A, B & C provide the comparable cost data for each IOU based on the 1998 gas prices. Figure 5 combines the Figure 4 series into one graph, and for the first time we have a representation of the total system. The MCP curves are based on the $SAHR_{AVE}$ values and the MC curves are based on ***SHIR*** values. The distances between these two curves allow us to appreciate the difference between MCP and MC that is due to the combination of heat rate and gas price differences -- the difference between average and incremental costs -- the difference between UPLAN MCP and Elfin MC.

Table 7 combines the heat rate data of Table 5 and the cost data that is based on these heat rates and the gas prices of Table 6. The MC values use the ***SHIR*** heat rates and the MCP values use the $SAHR_{AVE}$ heat rates.

TABLE 7: SUMMARY OF HEAT RATE AND 1998 FUEL COSTS

FORECAST YEAR = 1998 GAS PRICES = INTERIM FR 97	PG&E Figure 4A	SCE Figure 4B	SDG&E Figure 4C	AVERAGE Figure 5
SIHR HEAT RATES (Btu/kWh)	9,052	8,943	9,843	9,067
SAHR HEAT RATES (Btu/kWh)	10,495	11,217	11,081	10,939
MC - Dispatch Gas Price ($/MWh)	18.4	22.6	21.9	21.0
MC - Total Gas Price ($/MWh)	22.6	22.8	28.2	23.3
MCP - Dispatch Gas Price ($/MWh)	21.3	28.3	24.6	25.4
MCP - Total Gas Price ($/MWh)	26.2	28.6	31.7	28.0

This Table allows us to estimate the cumulative difference between the MC costs of dispatch in the regulated market relative and the MCP of the deregulated market. Whereas, the deregulated market is represented by an average dispatch cost of 21 $/MWh, the average MCP cost is estimated as 28 $/MWh -- 33 percent higher. It should be kept in mind that this ignores other factors in the market, particularly the effect of out-of-state resources. Based on various UPLAN runs, this 33 percent would apply about 70 - 75 percent of the time. Using 75 percent of 33 percent translates to 25 percent which compares to the 30 percent of Table 4 -- not the same but roughly comparable.

The MC-Dispatch Gas Price values in Table 7 suggest that in an integrated system using traditional dispatch decisions, the PG&E generating units would have had the most favorable economic position due to its low cost (18.4 $/MWh). Both the MCP-Dispatch Gas Price value (21.3 $/MWh) and MCP Total Gas Price value (26.2 $/MWh) suggest that the PG&E generating units still have the best position in the market.

It is important to keep in mind that these representations are exceedingly simplistic. First, they are based on the slow-start gas-fired units, only. Second, we are using these ***IHR*** and the $\boldsymbol{AHR_{AVE}}$ values based on a simplistic averaging system. Third, we are ignoring all system generation and transmission constraints. Finally, these calculations are for one year, only. There is no reason to believe that these representations are anything but illustrative, but as it turns out they are more accurate than would be expected.

Staff has made comparisons of these MC and MCP estimates and found that the MC-DGP estimate is within a few percent of actual single-area Elfin runs for all three IOUs. Similarly MC-TGP is within about 3 percent for PG&E and SCE, but SDG&E is about 15 percent higher than the actual Elfin runs. The larger error for SDG&E is due to slow-start units being relatively small in capacity and not being competitive with alternative sources of power when priced at total price of gas. The MCP-Total Gas Price estimate compared against the UPLAN simulations showed better correlation than one would expect. For 1998 and 1999, the statewide MCP estimate was within 3 percent. One should be careful about concluding too much about the accuracy of these calculations, but it appears that they are useful in the near term for rough estimates.

If the fuel cost data is backed out of the above calculations, equations for MC and MCP can be developed in terms of the gas prices:

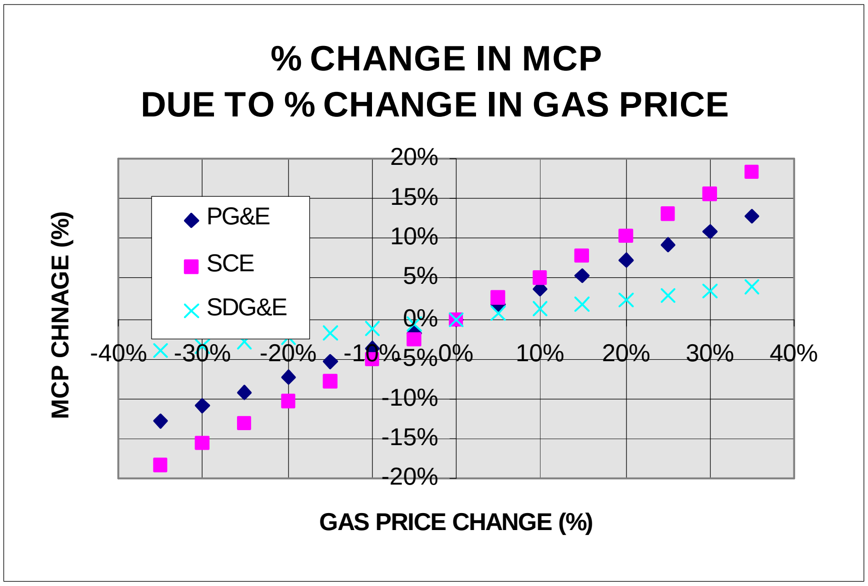
$$\boxed{\mathbf{MC_{EST}} = 3.32*\mathbf{DGP_{PG\&E}} + 4.56*\mathbf{DGP_{SCE}} + 0.27*\mathbf{DGP_{CW}} + 0.92*\mathbf{DGP_{SDG\&E}}}$$

DGP = Dispatch Gas Price in $/MMBtu

$\mathbf{MCP_{EST}} = 3.85^{*}\mathbf{TGP_{PG\&E}} + 5.70^{*}\mathbf{TGP_{SCE}} + 0.36^{*}\mathbf{TGP_{CW}} + 1.03^{*}\ \mathbf{TGP_{SDG\&E}}$

TGP = Total Gas Price in $/MMBtu

The $\mathbf{MCP_{EST}}$ equation can be graphically represented as shown in the following figure. The $\mathbf{MCP_{EST}}$ and this figure suggest that a 10 percent increase in PG&E's gas price has about a 5 percent increase in the MCP; SCE would have about 3.5 percent; and SDG&E would have about a 1.5 percent effect.



The $\mathbf{MCP_{EST}}$ is suspicious in that it suggests that SCE has the larger effect on MCP, whereas the UPLAN simulations suggest that the PG&E units have the larger effect. It also overstates the effect of SDG&E on the MCP.

Regardless of these shortcomings -- particularly in regard to estimating the MCP -- these admittedly coarse equations seem to be working for rough estimates of MC and MCP in the framework of the present set of assumptions.

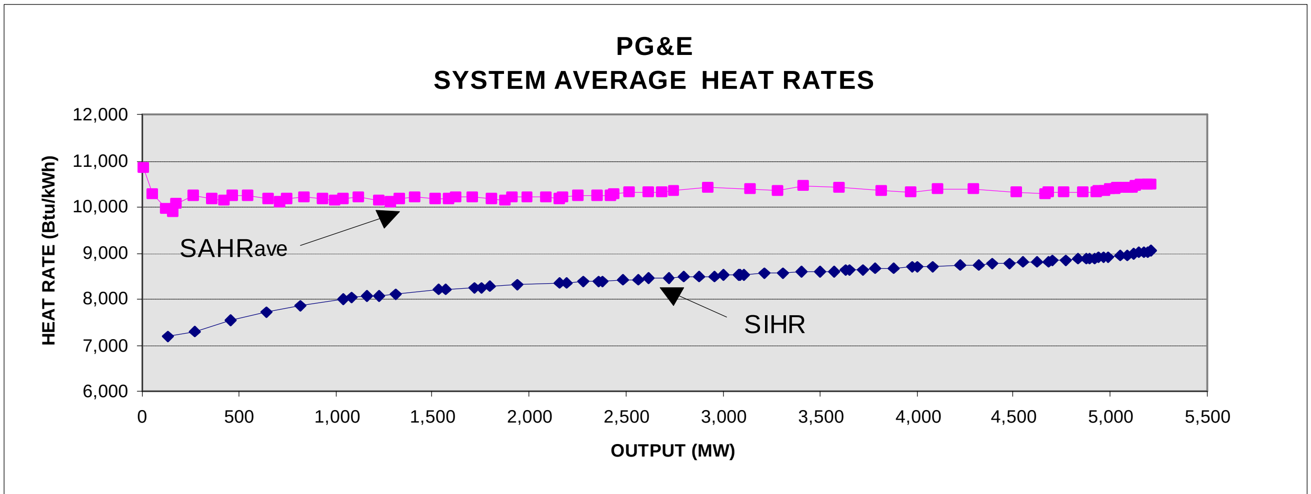


Figure 3A

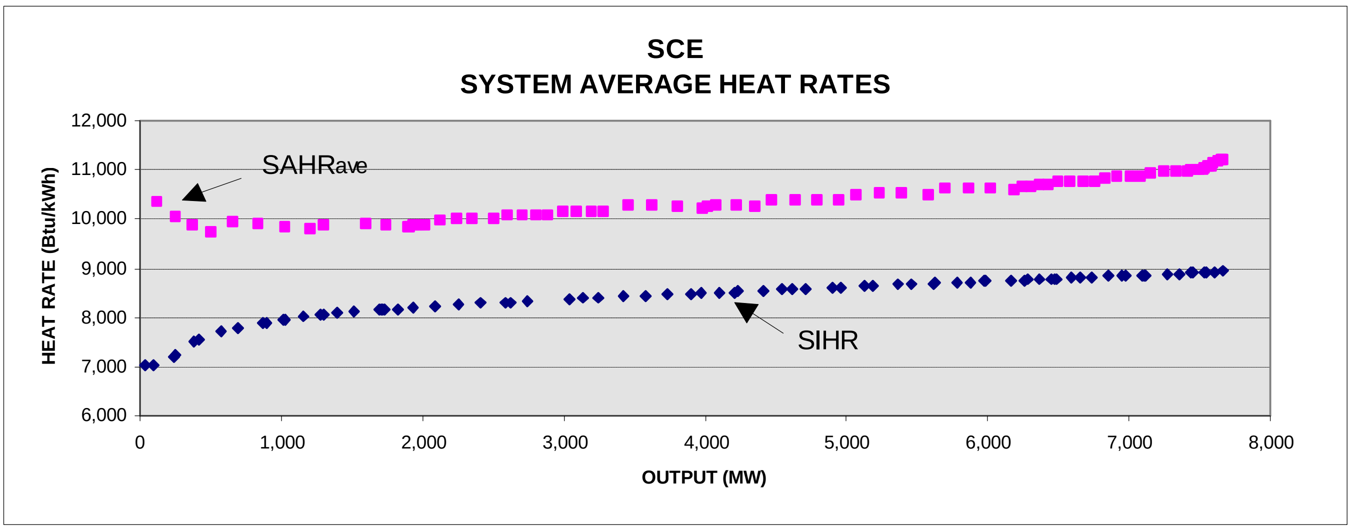


Figure 3B

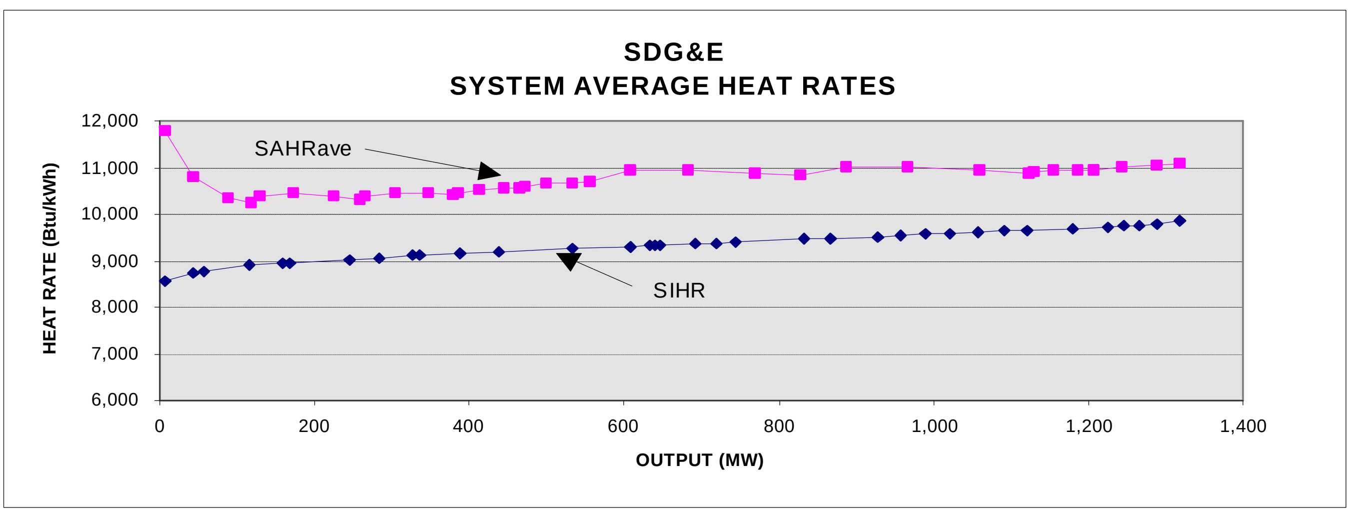


Figure 3C

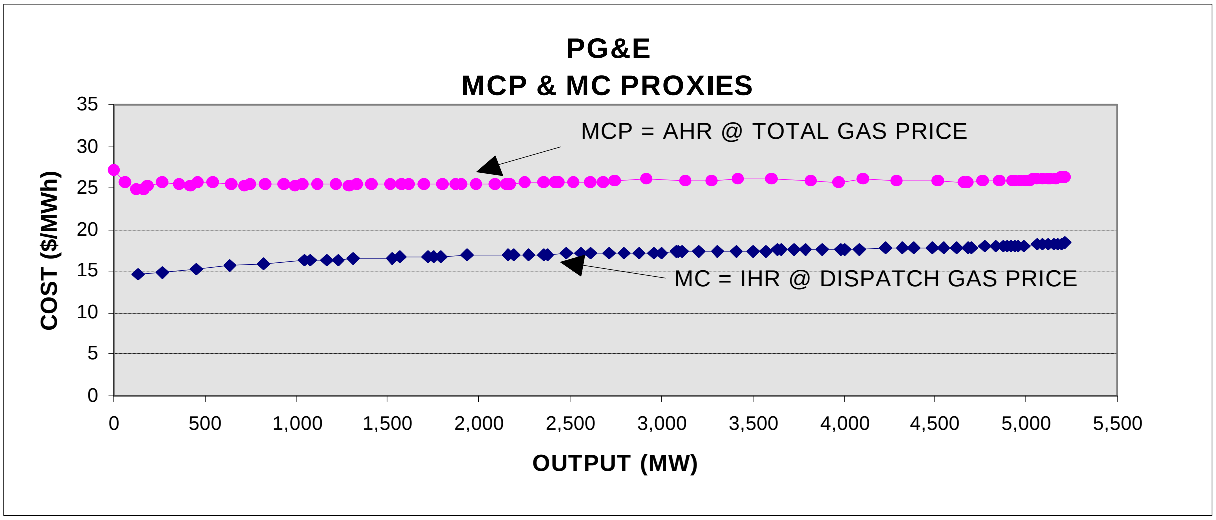


Figure 4A

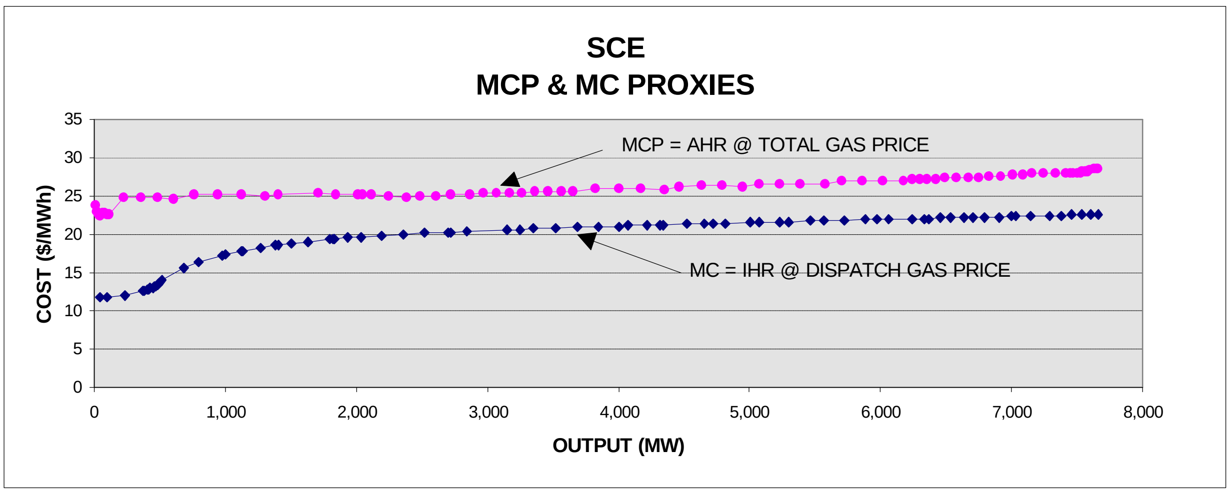


Figure 4B

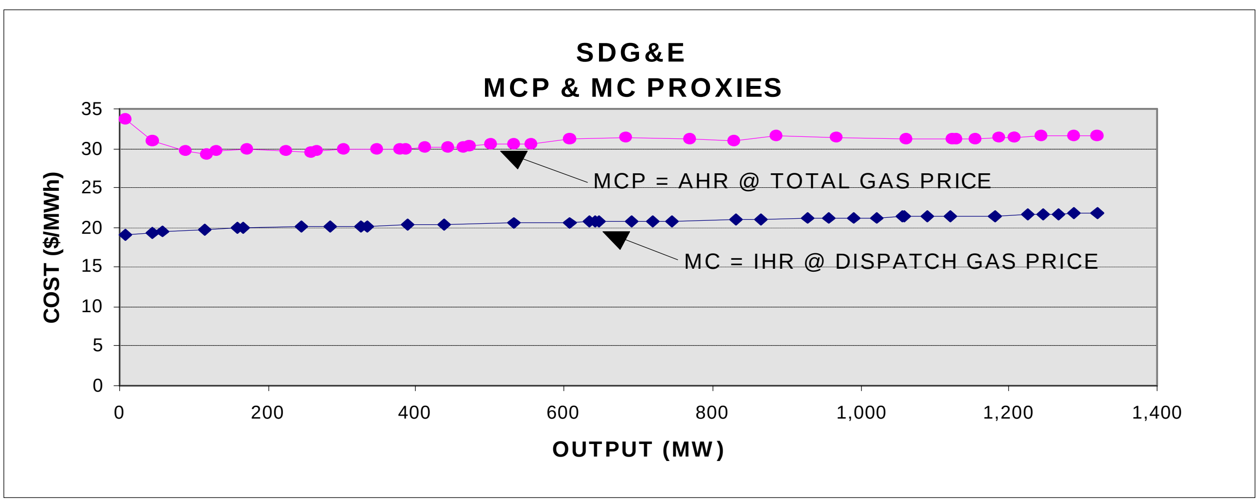
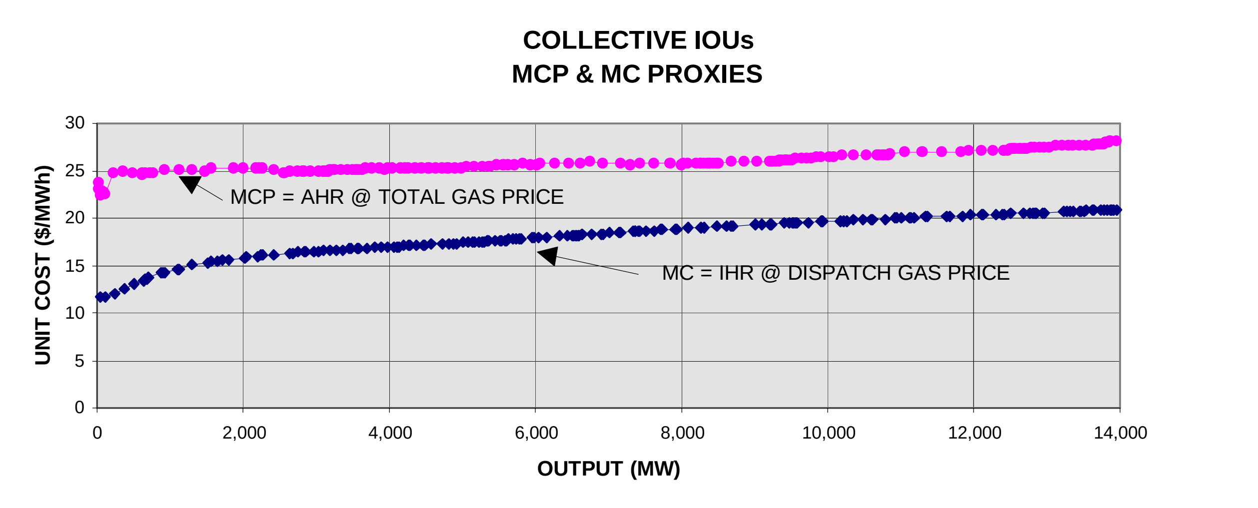


Figure 4C



COLLECTIVE IOUs
MCP & MC PROXIES
UNIT COST ($/MWh)
30
25
20
15
10
5
0
MCP = AHR @ TOTAL GAS PRICE
MC = IHR @ DISPATCH GAS PRICE
0
2,000
4,000
6,000
8,000
10,000
12,000
14,000
OUTPUT (MW)

Figure 5

V. ENERGY COMMISSION CONTACTS

The following is a list of the Energy Commission personnel who were involved directly or indirectly with this MCP forecast, along with their phone numbers, FAX numbers and EMAIL addresses. This list is intended to facilitate your information requests related to this study. If you are in doubt as to whom to contact, you can contact the primary author, who will direct you to the appropriate source. Copies of this report are available from the Energy Commission's Web Site: http://www.energy.ca.gov/energy. Alternatively, additional copies can be requested from Barbara Crume.

TABLE 8: ENERGY COMMISSION CONTACTS

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APPENDIX A
INTERIM FR 97 GAS PRICE FORECAST

Table A-1 summarizes the gas prices used in this Staff MCP Forecast, in both nominal (current) and real 1998 dollars. Figures A-1 through A-4 provide this same data in graphical format. Figures A-1 and A-2 present the nominal values and A-3 and A-4 present the real 1998 dollar values.

These are interim FR 97 gas prices that have been provided by the Energy Commission's Fuel's Office for the specific purpose of this MCP Forecast and do not necessarily reflect the final FR 97 prices -- although prices are not expected to change dramatically. When the FR 97 Gas Price Forecast is finalized and approved by the ER 98 Committee, it will become the official gas price forecast. If the values have changed significantly, the Staff MCP Forecast will be redone.

The irregular transition from 1998 to 2000 represents the price drop that is expected when the extensive reserves of the Gulf of Mexico enter the market, once the transportation facilities are complete. The effect of this in real dollars is that prices do not rise to their 1998 values until about 2112.

TABLE A-1: INTERIM FR 97 GAS PRICE FORECAST

FR 97 GAS PRICE FORECAST (11/17/97)
(Nominal $/MMBtu)

	PG&E		SCE		Cool water		SDG&E	
Year	Disp	Total	Disp	Total	Disp	Total	Disp	Total
------	PG&E		SCE		CW		SDG&E	
1998	2.03	2.50	2.58	2.58	1.67	2.11	2.22	2.86
1999	1.79	2.27	2.27	2.27	1.70	2.15	1.96	2.51
2000	1.71	2.20	2.31	2.31	1.77	2.23	1.99	2.64
2001	1.78	2.29	2.31	2.31	1.84	2.32	2.07	2.80
2002	1.86	2.38	2.42	2.42	1.92	2.41	2.17	2.93
2003	1.94	2.48	2.55	2.55	2.00	2.50	2.27	2.91
2004	2.03	2.60	2.68	2.68	2.09	2.63	2.37	3.12
2005	2.12	2.72	2.80	2.80	2.19	2.75	2.49	3.19
2006	2.22	2.85	2.96	2.96	2.30	2.89	2.62	3.42
2007	2.33	2.98	3.12	3.12	2.41	3.02	2.75	3.57
2008	2.47	3.12	3.29	3.29	2.54	3.17	2.89	3.73
2009	2.60	3.27	3.47	3.47	2.66	3.32	3.04	3.86
2010	2.75	3.44	3.66	3.66	2.80	3.49	3.22	4.09
2011	2.90	3.62	3.86	3.86	2.95	3.66	3.40	4.33
2012	3.06	3.80	4.09	4.09	3.10	3.84	3.60	4.54
2013	3.21	4.00	4.34	4.34	3.26	4.02	3.80	4.81
2014	3.39	4.20	4.59	4.59	3.43	4.22	4.01	5.05
2015	3.57	4.41	4.84	4.84	3.60	4.42	4.22	5.30

Apr 16, 1997	
Deflators	
1998	1.00
1999	1.02
2000	1.05
2001	1.08
2002	1.11
2003	1.15
2004	1.18
2005	1.22
2006	1.27
2007	1.31
2008	1.36
2009	1.41
2010	1.46
2011	1.51
2012	1.56
2013	1.62
2014	1.68
2015	1.74

FR 97 GAS PRICE FORECAST (11/17/97)
(1998 $/MMBtu)

	PG&E		SCE		Cool water		SDG&E	
Year	Disp	Total	Disp	Total	Disp	Total	Disp	Total

1998	2.03	2.50	2.58	2.58	1.67	2.11	2.22	2.86
1999	1.75	2.21	2.22	2.22	1.66	2.10	1.91	2.45
2000	1.62	2.09	2.20	2.20	1.68	2.12	1.89	2.51
2001	1.64	2.12	2.13	2.13	1.70	2.14	1.91	2.59
2002	1.67	2.14	2.17	2.17	1.72	2.16	1.94	2.63
2003	1.69	2.16	2.22	2.22	1.74	2.18	1.98	2.54
2004	1.71	2.20	2.27	2.27	1.76	2.22	2.00	2.64
2005	1.73	2.22	2.29	2.29	1.79	2.25	2.03	2.61
2006	1.75	2.25	2.34	2.34	1.81	2.28	2.06	2.70
2007	1.78	2.27	2.38	2.38	1.84	2.31	2.10	2.72
2008	1.82	2.30	2.42	2.42	1.87	2.34	2.13	2.75
2009	1.85	2.33	2.46	2.46	1.89	2.36	2.16	2.75
2010	1.89	2.36	2.51	2.51	1.92	2.39	2.21	2.81
2011	1.92	2.40	2.56	2.56	1.96	2.43	2.26	2.87
2012	1.96	2.44	2.61	2.61	1.99	2.46	2.30	2.90
2013	1.99	2.47	2.68	2.68	2.02	2.49	2.35	2.97
2014	2.02	2.50	2.74	2.74	2.05	2.52	2.39	3.02
2015	2.06	2.54	2.79	2.79	2.08	2.55	2.43	3.05

FR 97 Compared to FR 95

Table A-2 compares Interim FR 97 gas prices to FR 95 prices (used for ER 96). Figures A-5 and A-6 provide the same data in graphical form.

Except for the 1998 numbers, all gas prices are lower than they were in FR 95. The FR 97 values are as much as 30 percent lower in the outer years. Again, the net effect is that in real terms the 2012 values are no higher than 1998.

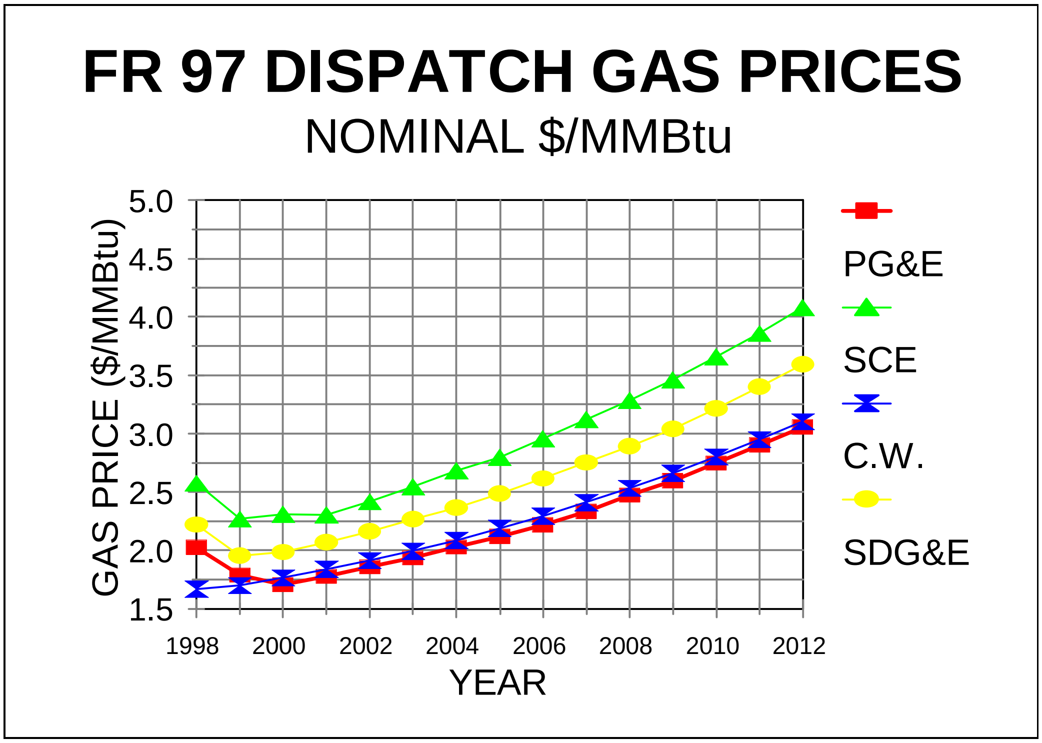

Figure A-1

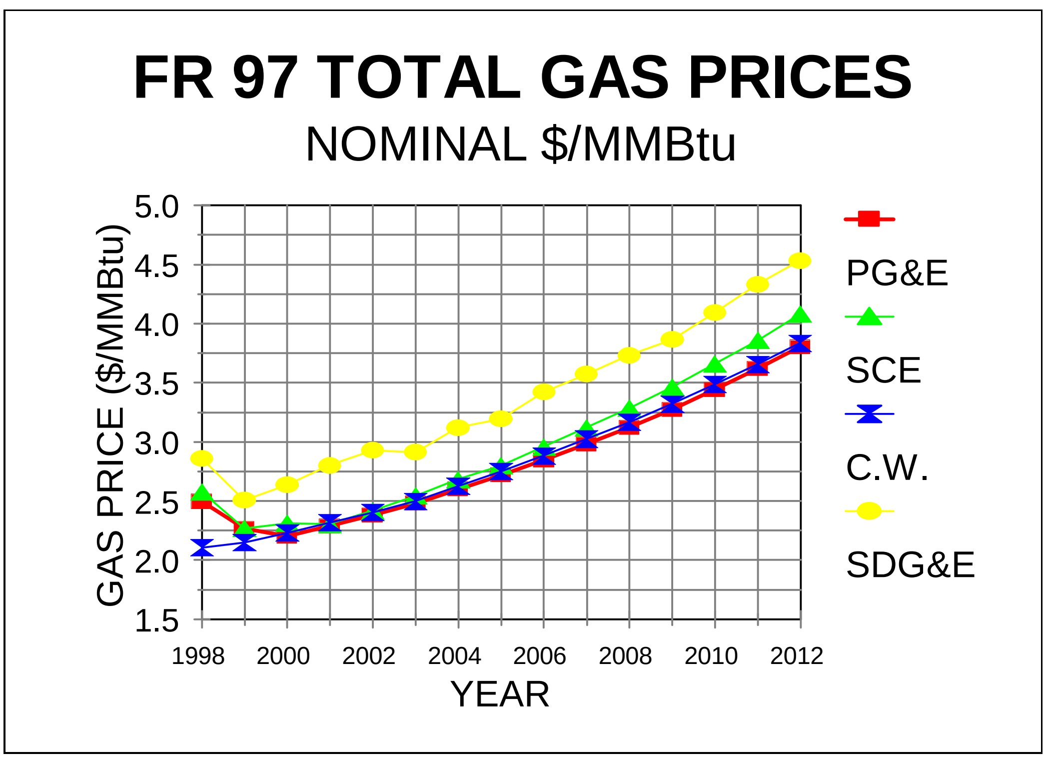

Figure A-2

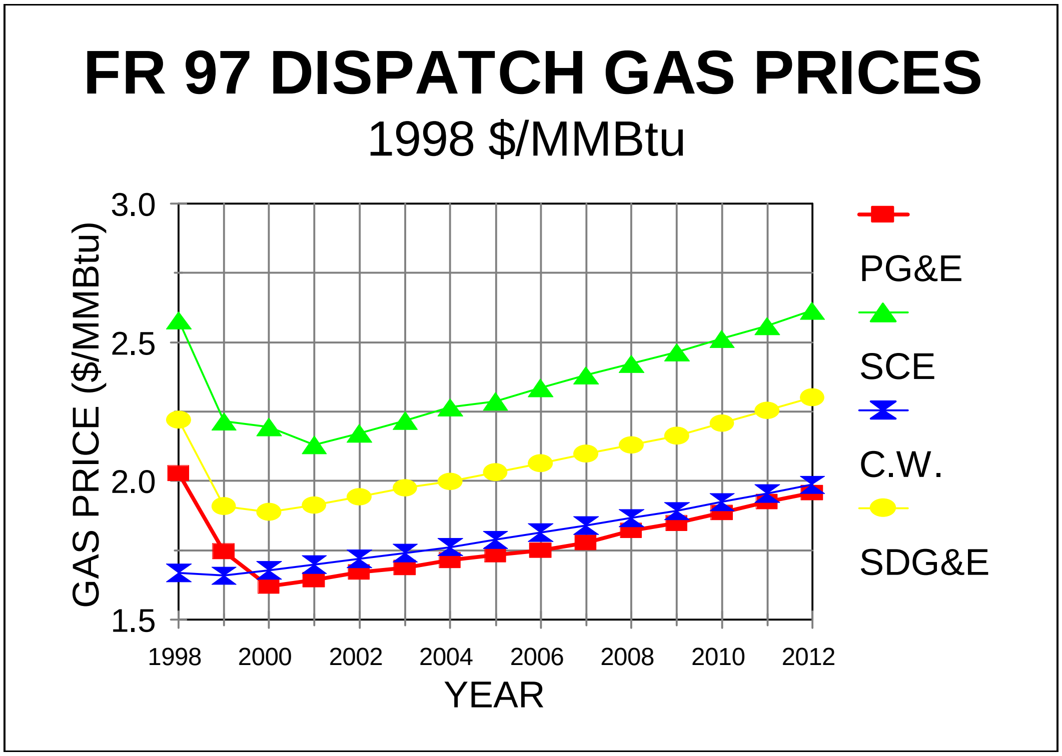

Figure A-3

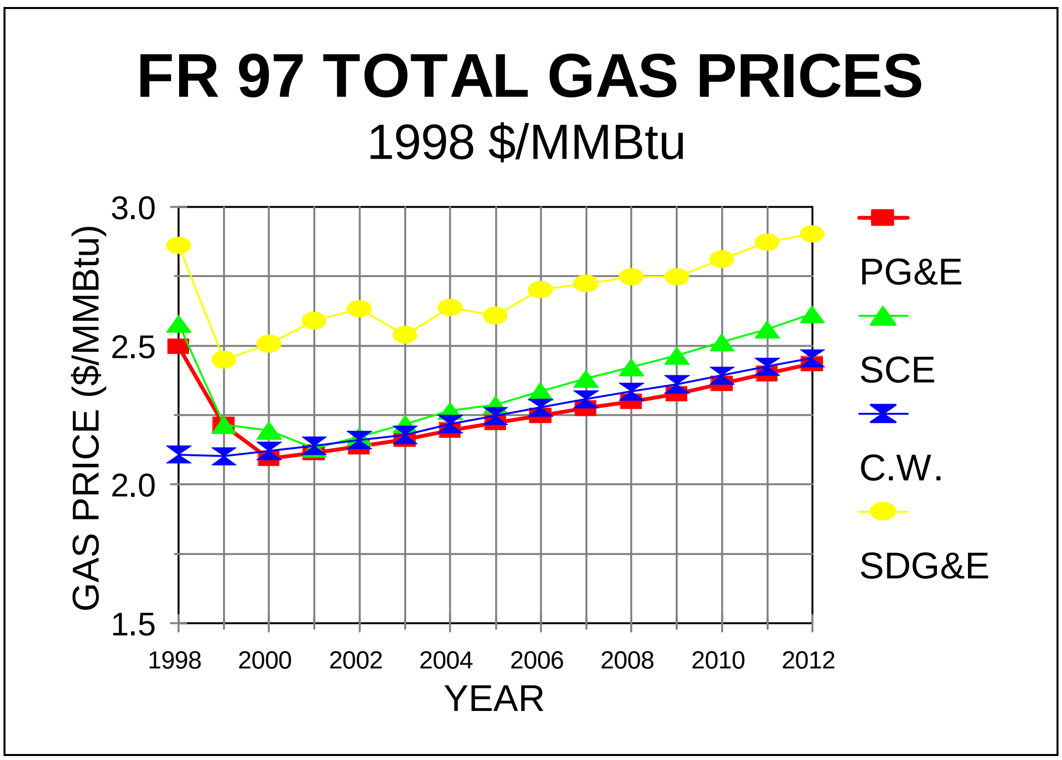

Figure A-4

TABLE A-2: COMPARISON OF INTERIM FR 97 GAS PRICES TO FR 95

FR 97 GAS PRICE FORECAST (11/17/97)
($/MMBtu)

	PG&E		SCE		Cool water		SDG&E	
Year	Disp	Total	Disp	Total	Disp	Total	Disp	Total

1998	2.03	2.50	2.58	2.58	1.67	2.11	2.22	2.86
1999	1.79	2.27	2.27	2.27	1.70	2.15	1.96	2.51
2000	1.71	2.20	2.31	2.31	1.77	2.23	1.99	2.64
2001	1.78	2.29	2.31	2.31	1.84	2.32	2.07	2.80
2002	1.86	2.38	2.42	2.42	1.92	2.41	2.17	2.93
2003	1.94	2.48	2.55	2.55	2.00	2.50	2.27	2.91
2004	2.03	2.60	2.68	2.68	2.09	2.63	2.37	3.12
2005	2.12	2.72	2.80	2.80	2.19	2.75	2.49	3.19
2006	2.22	2.85	2.96	2.96	2.30	2.89	2.62	3.42
2007	2.33	2.98	3.12	3.12	2.41	3.02	2.75	3.57
2008	2.47	3.12	3.29	3.29	2.54	3.17	2.89	3.73
2009	2.60	3.27	3.47	3.47	2.66	3.32	3.04	3.86
2010	2.75	3.44	3.66	3.66	2.80	3.49	3.22	4.09
2011	2.90	3.62	3.86	3.86	2.95	3.66	3.40	4.33
2012	3.06	3.80	4.09	4.09	3.10	3.84	3.60	4.54
2013	3.21	4.00	4.34	4.34	3.26	4.02	3.80	4.81
2014	3.39	4.20	4.59	4.59	3.43	4.22	4.01	5.05
2015	3.57	4.41	4.84	4.84	3.60	4.42	4.22	5.30

FR 95 GAS PRICE FORECAST (8/23/95)
($/MMBtu)

	PG&E		SCE		Cool water		SDG&E	
Year	Disp	Total	Disp	Total	Disp	Total	Disp	Total

1998	1.86	2.46	2.23	2.62	1.73	2.17	2.05	2.88
1999	1.93	2.53	2.22	2.63	1.83	2.30	2.15	2.92
2000	2.01	2.61	2.34	2.75	1.94	2.43	2.26	3.03
2001	2.11	2.72	2.48	2.89	2.06	2.57	2.39	3.17
2002	2.25	2.87	2.61	3.04	2.19	2.72	2.52	3.32
2003	2.40	3.07	2.79	3.23	2.36	2.90	2.70	3.52
2004	2.57	3.26	2.98	3.42	2.54	3.10	2.89	3.76
2005	2.75	3.44	3.17	3.62	2.72	3.30	3.09	3.97
2006	2.94	3.65	3.39	3.83	2.92	3.51	3.29	4.16
2007	3.16	3.87	3.61	4.05	3.13	3.73	3.51	4.38
2008	3.43	4.14	3.89	4.34	3.38	3.99	3.79	4.65
2009	3.71	4.45	4.20	4.65	3.64	4.26	4.10	4.96
2010	4.01	4.78	4.53	4.98	3.92	4.54	4.43	5.30
2011	4.32	5.12	4.88	5.34	4.21	4.83	4.78	5.65
2012	4.63	5.48	5.26	5.71	4.52	5.13	5.16	6.02
2013	4.99	5.88	5.66	6.11	4.88	5.48	5.56	6.42
2014	5.37	6.30	6.08	6.54	5.26	5.85	5.98	6.85
2015	5.77	6.75	6.52	6.99	5.66	6.24	6.43	7.30

FR 97 AS A PERCENT OF FR 95 GAS PRICES
(%)

	PG&E		SCE		Cool water		SDG&E	
Year	Disp	Total	Disp	Total	Disp	Total	Disp	Total

1998	109.2	101.5	115.5	98.4	96.6	97.2	108.2	99.5
1999	92.8	89.5	102.1	86.4	92.7	93.7	91.2	85.9
2000	85.1	84.3	98.6	84.1	90.9	91.9	88.0	87.2
2001	84.4	84.2	93.2	79.9	89.1	90.2	86.8	88.4
2002	82.9	83.0	92.6	79.6	87.4	88.6	85.8	88.3
2003	80.5	80.9	91.2	78.9	84.6	86.2	84.1	82.8
2004	78.9	79.7	90.1	78.5	82.1	84.9	81.8	83.1
2005	77.2	79.1	88.3	77.3	80.3	83.5	80.6	80.5
2006	75.4	78.1	87.4	77.3	78.7	82.2	79.4	82.3
2007	73.8	77.1	86.6	77.0	77.2	81.0	78.4	81.6
2008	72.2	75.3	84.6	75.9	75.1	79.5	76.3	80.2
2009	70.0	73.5	82.5	74.6	73.1	78.0	74.1	77.9
2010	68.5	72.0	80.9	73.5	71.5	76.7	72.6	77.3
2011	67.2	70.7	79.2	72.4	70.0	75.7	71.1	76.7
2012	66.0	69.4	77.7	71.6	68.7	74.8	69.7	75.3
2013	64.4	68.0	76.6	71.0	66.9	73.5	68.2	74.9
2014	63.0	66.6	75.4	70.2	65.3	72.2	67.0	73.8
2015	61.8	65.3	74.2	69.2	63.7	70.9	65.7	72.5

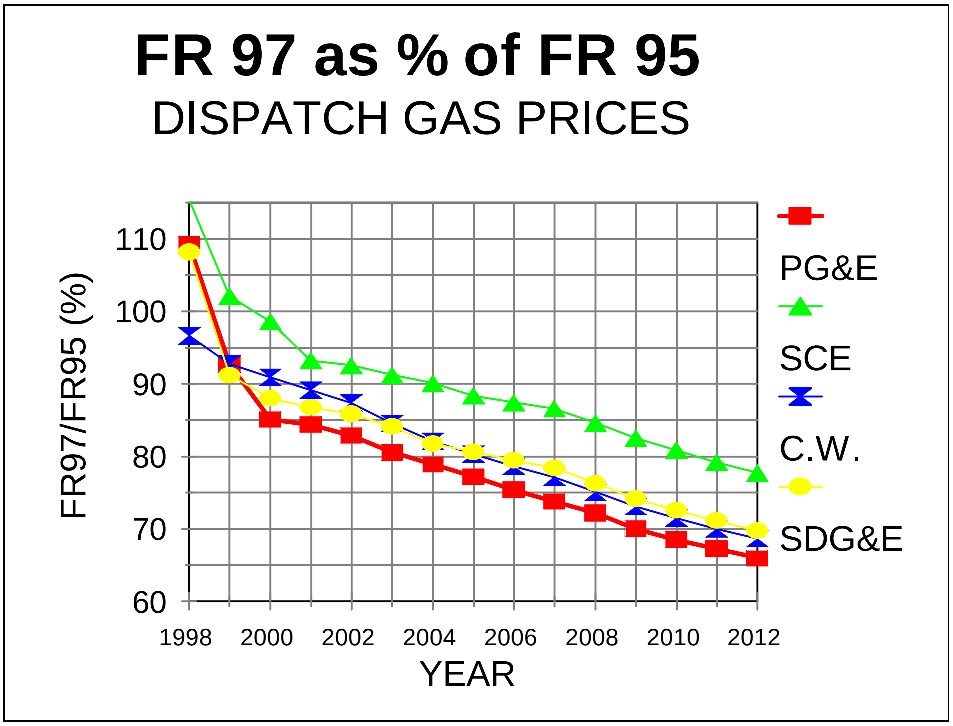

Figure A-5

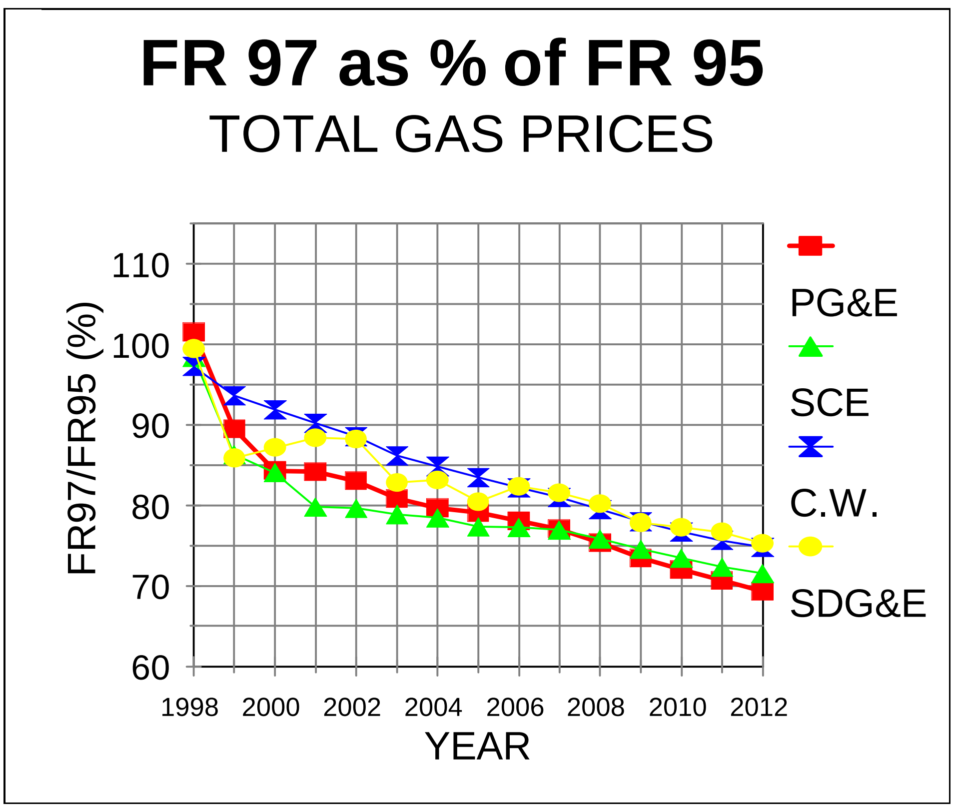

Figure A-6

APPENDIX B
VIABILITY OF NEW ENTRANTS
Richard Grix

The economic viability of existing and new units will depend on their ability to cover their costs from the income they can earn. For most generators bidding into the PX, their net income will be the difference between their total income, based on the MCP paid for their generation, and their fixed and variable costs. Some existing generators will receive additional income under reliability contracts with the ISO. Existing utility-owned generators that are not divested, however, will have the recovery of their remaining fixed capital costs guaranteed through the CTC during the transition period. The only costs that these existing generators have at risk are their fixed O&M costs. The utility generator can either hope that the MCP that it's paid is sufficient to cover both fixed and variable O&M, or if the generator is designated as needed for reliability purposes, then it can recover its costs through a reliability contract with the ISO. Because a new generator bidding into the PX does not have its capital costs covered under the CTC, and most likely will not have a reliability contract with the ISO, its total costs, capital and fixed and variable O&M, must be recovered based on just the MCP for its generation.

Existing generators in California that are not divested, or that are needed for reliability, will have recovery of their capital costs guaranteed through either the CTC, or through contracts with the ISO. The expectation is that these generators will have a strong incentive to bid close to their plant's variable operating cost and therefore set the market clearing price for most hours of the day. If this is the case, the MCP during the transition period will closely approximate the variable operating cost of existing utility generators. Even though the efficiency of the new units, such as gas-fired combined cycle plants, is significantly greater compared to the efficiency of the existing utility units, the resulting difference in operating costs may not be enough for new generators to recover all of their costs.[16] As the system needs new capacity the MCP will have to rise to attract new generators.

What are the costs that a new entrant into the market needs to recover from the MCP? The answer to this is sensitive to several assumptions regarding the plant's capacity factor, its efficiency, fixed and variable non-fuel operating costs, fuel related operating costs, and construction cost.

The plant's capacity factor is typically a function of system demand, and availability. Stone & Webster in their work for the Commission's ***Energy Technology Status Report*** reported that a combined cycle plant operating in the base load mode would have an expected capacity factor of 85 percent. However, it could vary from 50 to 95 percent depending on load conditions and where the plant is in its maintenance cycle. A plant's availability factor reflects the number of

[16] Recently built combined cycle facilities have an average heat rate of around 7,200 Btu/kWh. This assumes that the plant is operating near full capacity in all hours of operation (i.e. in a base load mode). The system average heat rate for existing utility gas-fired units in California is around 11,000 Btu/kWh.
1.

hours it is available to run. An availability factor of 93 percent is a reasonable expectation, based on a nominal forced outage rate of 2 percent and maintenance outage rate of 5 percent .[17]

The efficiency of the plant is measured by its heat rate. For recently built combined cycle plants, such as the GE 7FA, the Westinghouse 501G, the ABB GT24, and the Siemens V84.3A, the heat rate is around 7,200 Btu/kWh, assuming that they are operating primarily at their full load level. Further heat rate improvements are expected. The GE 7H combined cycle plant, that became available this year, is reported to have a heat rate of 6,300 Btu/kWh (high heat rate value).[18]

A plant's non-fuel O&M will vary depending on several factors. For this analysis the fixed and variable non-fuel O&M costs for a typical 220 MW, base-loaded combined cycle plant are estimated to be $22/kW-yr and $1.8/MWh (in 1998 $), respectively. The fixed cost would be approximately $13/kW-yr for an intermediate-duty plant.[19] The plant's fuel related O&M costs are the product of the assumed heat rate and fuel cost.

The ***instant cost***[20] of building a combined cycle plant or its "lump-sum, turnkey" (LSTK) price at a new site ranges from $553 to $803/kW (1998 dollars)[21]. This includes transmission interconnection costs, but does not include any transmission upgrade costs. The cost of recently installed combined cycle plants suggest that the price is more likely to be around the $800/kW range.[22]

The following assumptions are used to calculate a range of MCPs that would be needed to attract a new combined cycle plant in 1998.

Installed Plant Capacity	220 MW
Instant Plant Cost	$553 - $803/kW
Fixed Charge Rate	15%
Heat Rate	6300 - 7200 Btu/kWh

2. [17] According the Commission's Draft *Energy Technology Status Report* (ETSR), March 1996, the availability of a combined cycle plant will vary from year to year because the maintenance outage time varies from year to year. Base loaded combined cycles have maintenance cycles of three to six years that requires an outage ranging from 20 to 130 days. The impact of maintenance outages on availability over a six-year cycle would be 1.8 to 5.9 percent. Forced outage rates are relatively low, generally ranging from 0.5 to 4.0 percent. For planning purposes a 2 percent forced outage rate is recommended..
3.
4. [18] Gas Turbine World 1997 Handbook, Vol. 18, p. 56.
5.
6. [19] Due Diligence Database, Stone & Webster Engineering Corporation.
7.
8. [20] The instant cost is also referred to as the "overnight" costs because it assumes that plant is built overnight as opposed to the installed cost which incorporates inflation and interest payments incurred during construction.
9.
10. [21] Based on a compilation of historical costs and estimates for combined cycle projects in the United States by Stone & Webster for the Commission's ETSR, Draft, March 1996.
11.
12. [22] Stone & Webster's has reported in its work for the Commission's Energy Technology Status Report (ETSR) that the information it has gathered on independent power producer projects across the country have total project costs of $834 to $1,981 per kW (1998 dollars). These estimates would be equivalent to the plant's ***installed cost***.

Fixed Non-fuel O&M $22/kW-yr
Variable Non-fuel O&M $1.8/MWh
Gas Price (1998 $s) $2.20 - $2.50/MMBtu
Capacity Factor 93% - 85%

Annualized Capital Cost = (Instant Plant Cost x Fixed Charge Rate)
= $82.95/kW-yr - $120.45/kW-yr

= (Plant Capacity x $82.95 /kW-yr - $120.45/kW-yr)
= $18.25 - $26.50 Million

MWh of Generation = (Capacity Factor x Capacity x 8,760 hrs)
= 1,792,296 - 1,638,120 MWh

Capital Cost Recovery Rate = (Annualized Capital Cost/MWh of Generation)
= $10.18/MWh - $16.18/MWh

Variable Fuel O&M Cost = (Heat Rate x Gas Price)
= $13.86/MWh - $18.00/MWh

Fixed Non-fuel O&M Recovery Rate = ($22/kW-yr x Plant Capacity)/MWh of Generation
= $2.70/MWh - $2.95/MWh

MCP Needed for New Entrant = (Capital Cost RR + Variable Fuel O&M + Fixed and Variable Non-fuel O&M)
= ($28.54/MWh - $38.93/MWh)

Based on these calculations, it is clear that the MCP needed to cover the cost of a new entrant encompasses a wide range. The prevailing optimism among investors is that a new combined cycle can be built at the $28 per MWh figure based on 1998 gas prices. Staff feels that this is probably naive and that the investors are too optimistic about the actual costs and the likely capacity factor. There are claims of installed costs as low as $500 per kW and fixed O&M costs as low as $1 per MWh. Based on existing units, these seem unrealistic. Also, the amount of must-run generation in California will exacerbate problems of over generation especially during minimum load conditions. This means that a new entrants expectation of a high capacity factor may not be possible.

Nevertheless, Staff acknowledges what appears to be a very persistent perception that new investments will occur based on the belief that a MCP of $28/MWh (1998$) is sufficient. Looking at the impact of competition on costs in other deregulated industries, Staff believes that it is possible that this price may actually occur, and therefore accepts this estimate in developing the MCP Forecast.

APPENDIX C
A SIMPLISTIC MARKET MODEL

This Appendix describes the development of the simplistic model described in Section V, of the main body of this report. This model provides a very simplified characterization of the market that does not pretend to have the accuracy of a model such as UPLAN but is, at the same time, more useful in visualizing the competitive market as it compares to the existing regulated market. It does this by comparing the Marginal Cost (MC) of the regulated market to the Market Clearing Price (MCP), using the heat rate and fuel cost data of the IOU slow-start gas-fired units for the three IOUs: PG&E, SCE and SDG&E -- pre-divestiture. At the same time, it provides a mechanism for making crude estimates of the MCP.

Incremental Heat Rates (***IHR***) are used for characterizing the MC and Average Heat Rates (***AHR***) are used for characterizing MCP. The block ***IHRs*** are used directly but the ***AHRs*** must be converted to ***AHR*** averages ($\boldsymbol{AHR_{AVE}}$), as will be explained below. From this data, system ***IHRs*** (***SIHR***) and system $\boldsymbol{AHR_{AVE}}$ ($\boldsymbol{SAHR_{AVE}}$) are developed. Finally, using the Interim November 17, 1997 FR 97 Gas Price Forecast, the corresponding costs are developed which can stand as proxies for MC and MCP.

BLOCK UNIT INCREMENTAL HEAT RATES

The Incremental Heat Rates (***IHRs***) are calculated from the UPLAN/Elfin block average heat rate data -- except for a few cases where the ***IHRs*** were available directly. Where units have the same capacity and similar heat rates, they are combined into one equivalent unit by averaging the block data.

The calculations are illustrated in Table C-1 using Moss Landing 7. The Input-Output Curve is first calculated by multiplying each ***AHR*** by its corresponding capacity. The ***IHR*** is then calculated for each block as the increment in the I/O Curve divided by the increment in Capacity. For example, Block 2 is (1,966,735-997,950)/(185-50) = 7,176 Btu/kWh. It is necessary to understand that the block 1 ***IHR*** is not really a ***IHR*** as it represents the heat rate for the minimum block, which can not be used in a dispatch decision. Therefore, only blocks 2-5 are calculated.

TABLE C-1: ELFIN HEAT RATE DATA FOR MOSS LANDING 7.

BLOCK #	CAPACITY		***AHR***	I/O Curve	***IHR***
	(%)	(MW)	(Btu/kWh)	(1000 Btu/hr)	(Btu/kWh)
1	6.8%	50	19,959	997,950	19,959
2	25.0%	185	10,631	1,966,735	7,176
3	50.1%	370	9,268	3,429,160	7,905
4	80.0%	591	8,962	5,296,542	8,450
5	100.0%	739	8,917	6,589,663	8,737

The resulting ***IHRs*** and their corresponding incremental block capacities (INC) are summarized in Table C-2.

TABLE C-2: BLOCK INCREMENTAL HEAT RATES (*IHRs*)

	BLOCK 2		BLOCK 3		BLOCK 4		BLOCK 5	
	INC MW	***IHR*** Btu/kWh	INC MW	***IHR*** Btu/kWh	INC MW	***IHR*** Btu/kWh	INC MW	***IHR*** Btu/kWh
PG&E UNITS								
Contra Costa 6	39	8,756	85	8,555	102	8,877	68	9,811
Contra Costa 7	39	8,496	85	8,503	102	8,933	68	9,754
Humboldt 1&2	16	10,543	27	10,366	31	11,392	21	13,521
Hunters Point 2	17	10,364	27	10,981	32	11,861	21	12,701
Hunters Point 3	17	9,876	27	10,861	32	12,246	21	13,552
Hunters Point 4	20	8,873	82	9,044	96	9,379	66	9,724
Morro Bay 1&2	20	9,407	82	9,441	96	9,675	66	10,081
Morro Bay 3	39	9,056	84	9,064	101	9,100	68	9,159
Morro Bay 4	39	8,703	84	8,848	101	9,083	68	9,314
Moss Landing 6	135	7,370	185	8,146	221	8,668	148	8,714
Moss Landing 7	135	7,196	185	7,890	221	8,485	148	8,760
Pittsburg 1&2	20	9,079	82	9,003	96	9,391	66	10,331
Pittsburg 3&4	20	9,276	82	8,983	96	9,529	66	11,211
Pittsburg 5	35	8,744	82	8,900	97	9,135	65	9,344
Pittsburg 6	35	8,821	82	8,868	97	9,135	65	9,579
Pittsburg 7	60	8,555	180	8,476	216	8,762	144	9,469
Potrero 3	5	9,066	52	8,924	62	9,276	41	10,341
SCE UNITS								
Alamitos 1&2	70	9,127	90	9,341	90	9,663	80	10,047
Alamitos 3&4	120	8,443	160	8,639	160	8,933	160	9,305
Alamitos 5&6	160	8,155	180	8,656	180	9,074	180	9,375
Cool Water 1	13	9,320	13	9,549	13	9,808	9	10,050
Cool Water 2	16	9,368	16	9,540	16	9,742	14	9,960
Cool Water 3&4	40	7,013	60	7,064	140	7,334	132	8,018
El Segundo 1&2	70	9,224	90	9,394	90	9,631	80	9,898
El Segundo 3&4	120	8,395	160	8,576	160	8,839	190	9,198
Etiwanda 1&2	60	9,264	60	9,627	60	10,104	64	10,719
Etiwanda 3&4	120	8,438	160	8,641	160	8,943	160	9,322
Highgrove 1&2	10	8,413	20	8,438	18	8,471	10	8,495
Highgrove 3&4	14	7,899	26	8,096	30	8,338	9	8,485
Huntington 1&2	100	8,552	100	8,768	100	9,050	90	9,379
Long Beach 8&9	110	9,608	120	9,647	110	9,717	150	9,836
Mandaly 1&2	100	8,443	105	8,799	95	9,279	90	9,842
Ormond Beach 1	120	8,171	130	8,429	120	8,742	130	9,112
Ormond Beach 2	175	8,192	175	8,459	175	8,818	175	9,268
Redondo 5&6	70	8,992	90	9,134	90	9,324	80	9,535
Redondo 7&8	100	8,557	300	8,759	140	9,028	160	9,248
San Bernardino 1&2	28	8,681	28	9,056	28	9,384	28	9,667
SDG&E UNITS								
Encina 1	7	9,736	27	9,815	32	10,231	21	10,909
Encina 2	6	9,763	26	9,889	31	10,258	21	10,760
Encina 3	8	9,374	27	9,635	33	10,375	22	11,377
Encina 4	53	9,472	74	9,617	87	9,966	59	10,437
Encina 5	59	9,016	79	9,190	94	9,605	63	10,163
South Bay 1	7	8,560	37	8,764	44	9,368	29	10,169
South Bay 2	8	9,127	37	9,287	45	9,763	30	10,407
South Bay 3	13	8,937	43	9,082	51	9,487	34	10,027
South Bay 4	1	10,278	36	10,268	45	10,741	30	11,797

BLOCK AVERAGE HEAT RATES

At first blush, it would appear that the ***AHR*** could be obtained directly from the UPLAN/Elfin heat rate data -- such as those shown in Table C-1. This is not possible because the ***AHR*** and ***IHR*** data in Table C-1 are not directly comparable. The ***IHR*** of 7,905 Btu/kWh of block 3, for example, is an average for the Block 3, ranging from 185 MW to 370 MW. But the corresponding ***AHR*** of 9,268 Btu/kWh is the heat rate at 370 MW. In order to make these values comparable, an average ***AHR*** value for the range of 185 MW to 370 MW has to be calculated. This value is designated as AHR_{AVE}, and calculated using calculus. The ***AHR*** curve is integrated over each of its blocks and that value is divided by the number of megawatts associated with the respective block. The process is as follows.

The Input-Output Curve (Btu/hr) can be represented by a third order equation:

$$Y=aX^3+bX^2+cX+d$$

Where: ***Y*** is the Input fuel (Btu/hr)
X is the Output generation (MW)

The Average Heat Rate curve (***AHR***) is by definition equal to the Input-Output curve divided by the respective capacity, ***Y/X:***

$$AHR = Y/X = (aX^3+bX^2+cX+d)/X$$

The average ***AHR***, AHR_{AVE}, is the integral of ***AHR*** from X_1 to X_2 divided by the quantity $X_2 - X_1$:

AHR_{AVE} = [⇩ ***AHR dx*** {from X_1 to X_2}] / $(X_2 - X_1)$

Where: X_1 = ***Minimum operating level of the block (MW)***
X_2 = ***Maximum operating level of the block (MW)***

The integration of ***AHR***, (⇩ ***AHR dx***), is as follows:

⇩ ***AHR dx*** **=** ⇩ ☯$(aX^3+bX^2+cX+d)/X]dx = a/3 \cdot X^3 + b/2 \cdot X^2 + c \cdot X + d \cdot ln(X)$

Or in spreadsheet language:

⇩ ✌☞***R dx*** **=** ⇩ ☯***(a*X^3+b*X^2+c*X+d)/X]dx = a/3*X^3+b/2*X^2+c*X+d*ln(X)***

The complete step-by-step process of calculating AHR_{AVE} is illustrated by again using Table C-1. The Elfin/UPLAN heat rate data is entered into an Excel spreadsheet. Only the I/O curve data is necessary for this process -- the rest of the data is not relevant to this process.

Using the I/O curve data of Table C-1, an Excel graph is prepared as shown in Figure C-1.

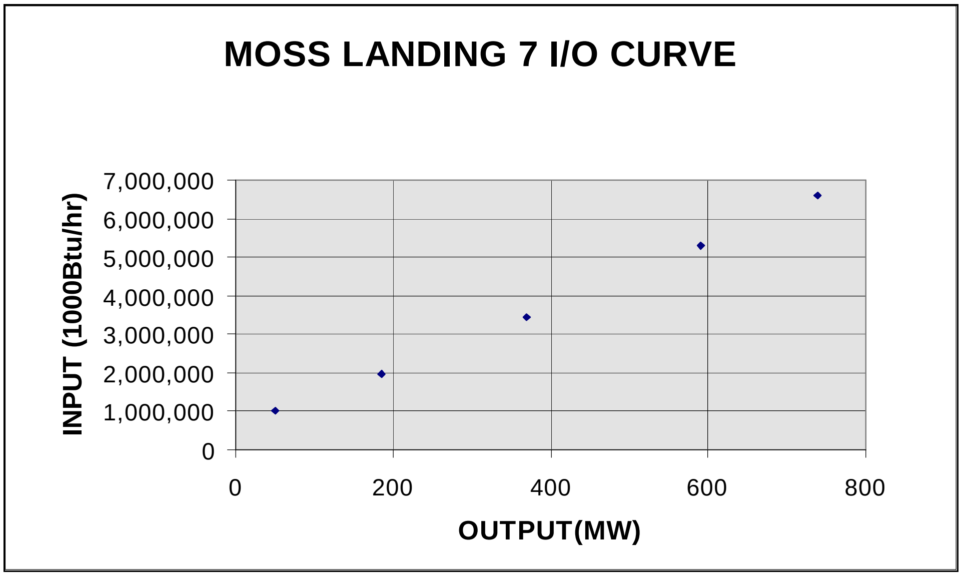

Figure C-1

Next, the Excel feature of "insert trendline" is used to identify a third order equation that fits the data points -- the option to print the equation on the graph is selected. This results in Figure C-2.

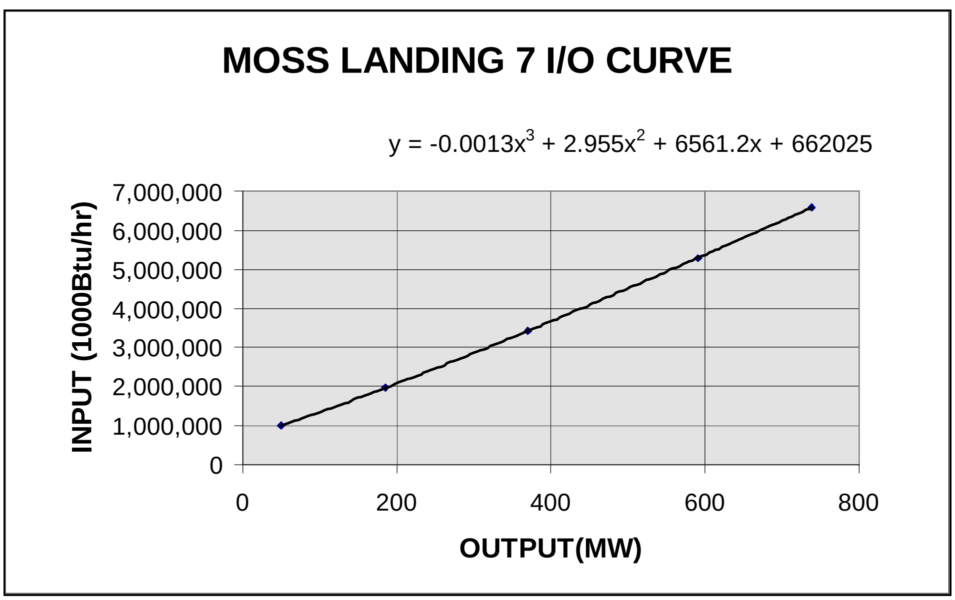

Figure C-2

The coefficients, ***a - d***, along with the values of X_1 and X_2 for each block is copied onto the spreadsheet. The formula for ⇩***AHR dx*** is entered onto the Excel spreadsheet in two places: once for calculating the value of ⇩***AHR dx*** for X_1 and once for X_2. For the first block (from 50 MW to 185 MW) this would be:

a = -0.0013 X_1 = 50 MW ⇩ $AHR(X_1)\ dx = 1/3*a*X_1\hat{}3+1/2*b*X_1\hat{}2+c*X_1+d*ln(X_1)$
b = 2.955 X_2 = 185 MW ⇩ $AHR(X_2)\ dx = 1/3*a*X_2\hat{}3+1/2*b*X_2\hat{}2+c*X_2+d*ln(X_2)$
c = 6561.2
d = 662,025

Finally, the two values of ⇩ ***AHR dx*** are subtracted from one another and the resulting value is divided by the difference of the $X_2 - X_1$ values:

AHR_{AVE} = [⇩ $AHR(X_2)\ dx$ - ⇩ $AHR(X_1)\ dx$] / $(X_2 - X_1)$

Excel then makes the following calculations:

⇩ $AHR(X_2)\ dx = a/3*X_2\hat{}3+b/2*X_2\hat{}2+c*X_2+d*ln(X_2)$
$= -0.0013/3 \times 185^3 + 2.955/2 \times 185^2 + 6561.2 \times 185 + 662025 \times \ln(185) = 4{,}717{,}651.8$

⇩ $AHR(X_1)\ dx = a/3*X_1\hat{}3+b/2*X_1\hat{}2+c*X_1+d*ln(X_1)$
$= -0.0013/3 \times 50^3 + 2.955/2 \times 50^2 + 6561.2 \times 50 + 662025 \times \ln(50) = 2{,}921{,}556.6$

AHR_{AVE} = (4,717,651.8 - 2,921,556.6) / (185 - 50) = 1,796,095.2 / 135 = **13,304 Btu/kWh**

Table C-3 summarizes the coefficients (***a - d***) and the minimum and maximum capacities that describe each equation. Table C-4 provides the resulting block AHR_{AVEs} for each IOU unit.

TABLE C-3: COEFFICIENTS FOR HEAT RATE EQUATIONS

					OUTPUT (MW)	
	a	**b**	**c**	**d**	**MIN**	**MAX**
PG&E UNITS						
Contra Costa 6	0.0148	-6.0775	9356.2	180,146	46	340
Contra Costa 7	0.0099	-2.9176	8746.7	223,144	46	340
Humboldt 1&2	0.2946	-30.3370	11330.0	99,926	10	105
Hunters Point 2	0.0116	12.9790	9870.6	115,531	10	107
Hunters Point 3	0.0144	21.0770	9080.0	117,483	10	107
Hunters Point 4	0.0010	1.3752	8659.0	205,948	62	326
Morro Bay 1&2	0.0049	-1.1685	9498.3	200,714	62	326
Morro Bay 3	0.0006	-0.1178	9063.6	190,385	46	338
Morro Bay 4	0.0004	1.0588	8559.2	194,590	46	338
Moss Landing 6	-0.0021	3.6945	6598.2	657,281	50	739
Moss Landing 7	-0.0013	2.9550	6561.2	662,025	50	739
Pittsburg 1&2	0.0148	-5.3036	9610.6	293,691	62	326
Pittsburg 3&4	0.0300	-12.1140	10551.0	219,614	62	326
Pittsburg 5	-0.0001	1.3632	8752.4	218,209	46	325
Pittsburg 6	0.0051	-1.0774	8894.6	177,052	46	325
Pittsburg 7	0.0023	-1.8450	8951.1	632,496	120	720
Potrero 3	0.0468	-11.9850	9908.0	70,409	47	207
SCE UNITS						
Alamitos 1&2	0.0018	0.8174	9018.2	397,249	20	350
Alamitos 3&4	0.0005	0.4401	8338.1	677,108	40	640
Alamitos 5&6	-0.0006	2.2408	6843.4	1,000,000	260	960
Cool Water 1	0.0293	6.1850	8979.5	48,471	17	65
Cool Water 2	0.0203	3.2256	9148.4	56,315	19	81
Cool Water 3&4	0.0035	-1.4482	7206.1	993,648	140	512
El Segundo 1&2	0.0010	0.7726	9129.0	373,847	20	360
El Segundo 3&4	0.0004	0.4377	8294.0	652,689	40	670
Etiwanda 1&2	0.0053	1.7528	9044.1	315,310	20	264
Etiwanda 3&4	0.0005	0.4642	8328.1	585,227	40	640
Highgrove 1&2	0.0004	0.8061	8392.3	327,238	8	66
Highgrove 3&4	-0.0086	5.6470	7715.1	588,318	10	89
Huntington 1&2	0.0011	0.6180	8411.7	326,693	40	430
Long Beach 8&9	0.0004	-0.0512	9600.9	210,025	70	560
Mandaly 1&2	0.0020	0.8052	8238.8	301,952	40	430
Ormond Beach 1	0.0006	0.3588	7773.3	737,960	250	750
Ormond Beach 2	0.0005	0.4250	8043.1	590,522	50	750
Redondo 5&6	0.0007	0.6815	8910.0	453,856	20	350
Redondo 7&8	0.0002	0.2479	8345.6	727,238	260	960
San Bernardino 1&2	-0.0099	7.9479	8260.7	267,439	14	126
SDG&E UNITS						
Encina 1	0.0717	-4.9251	9848.2	66,695	20	107
Encina 2	0.0405	-0.0360	9699.9	100,850	20	104
Encina 3	0.0717	0.0704	9246.0	91,919	20	110
Encina 4	0.0048	-0.0103	9438.4	164,658	20	293
Encina 5	0.0049	0.0026	8975.0	193,103	20	315
South Bay 1	0.0321	0.1005	8445.3	109,919	30	147
South Bay 2	0.0249	-0.0036	9040.9	102,533	30	150
South Bay 3	0.0160	0.0503	8868.4	107,907	30	171
South Bay 4	0.0742	-11.5250	10835.0	162,660	38	150

TABLE C-4: BLOCK AVERAGES OF AVERAGE HEAT RATES (AHR_{AVE})

	BLOCK 2		BLOCK 3		BLOCK 4		BLOCK 5	
	IC	***AHR***	IC	***AHR***	IC	***AHR***	IC	***AHR***
	MW	Btu/kWh	MW	Btu/kWh	MW	Btu/kWh	MW	Btu/kWh
PG&E UNITS								
Contra Costa 6	39	11,860	85	10,300	102	9,579	68	9,479
Contra Costa 7	39	12,112	85	10,361	102	9,622	68	9,517
Humboldt 1&2	16	16,853	27	13,245	31	12,142	21	12,167
Hunters Point 2	17	16,865	27	13,382	32	12,517	21	12,433
Hunters Point 3	17	16,339	27	12,974	32	12,336	21	12,471
Hunters Point 4	20	11,642	82	10,585	96	9,985	66	9,854
Morro Bay 1&2	20	12,246	82	11,128	96	10,438	66	10,266
Morro Bay 3	39	12,056	84	10,616	101	9,950	68	9,712
Morro Bay 4	39	11,694	84	10,292	101	9,714	68	9,561
Moss Landing 6	135	13,370	185	9,918	221	9,273	148	9,115
Moss Landing 7	135	13,304	185	9,758	221	9,079	148	8,949
Pittsburg 1&2	20	13,412	82	11,673	96	10,573	66	10,339
Pittsburg 3&4	20	12,905	82	11,388	96	10,408	66	10,341
Pittsburg 5	35	12,186	82	10,598	97	9,907	65	9,712
Pittsburg 6	35	11,709	82	10,352	97	9,751	65	9,625
Pittsburg 7	60	13,001	180	11,062	216	9,977	144	9,705
Potrero 3	5	10,853	52	10,207	62	9,689	41	9,686
SCE UNITS								
Alamitos 1&2	70	17,605	90	12,222	90	11,084	80	10,734
Alamitos 3&4	120	16,210	160	11,407	160	10,311	160	9,960
Alamitos 5&6	160	10,532	180	9,810	180	9,560	180	9,491
Cool Water 1	13	11,259	13	10,587	13	10,343	9	10,264
Cool Water 2	16	11,401	16	10,650	16	10,370	14	10,262
Cool Water 3&4	40	13,307	60	11,822	140	10,361	132	9,506
El Segundo 1&2	70	17,208	90	12,131	90	11,038	80	10,678
El Segundo 3&4	120	15,882	160	11,251	160	10,188	190	9,825
Etiwanda 1&2	60	16,432	60	12,244	60	11,371	64	11,106
Etiwanda 3&4	120	15,141	160	11,005	160	10,078	160	9,798
Highgrove 1&2	10	34,940	20	20,641	18	15,481	10	13,820
Highgrove 3&4	14	44,598	26	24,520	30	17,262	9	15,100
Huntington 1&2	100	12,570	100	10,331	100	9,822	90	9,666
Long Beach 8&9	110	11,404	120	10,506	110	10,230	150	10,107
Mandaly 1&2	100	12,114	105	10,087	95	9,706	90	9,664
Ormond Beach 1	120	10,354	130	9,753	120	9,486	130	9,382
Ormond Beach 2	175	13,188	175	10,168	175	9,595	175	9,442
Redondo 5&6	70	18,702	90	12,511	90	11,144	80	10,661
Redondo 7&8	100	10,808	300	9,995	140	9,633	160	9,548
San Bernardino 1&2	28	18,968	28	13,553	28	12,072	28	11,426
SDG&E UNITS								
Encina 1	7	12,632	27	11,483	32	10,831	21	10,737
Encina 2	6	14,131	26	12,451	31	11,406	21	11,135
Encina 3	8	13,155	27	11,675	33	10,933	22	10,891
Encina 4	53	13,472	74	11,055	87	10,494	59	10,398
Encina 5	59	13,485	79	10,741	94	10,144	63	10,055
South Bay 1	7	11,778	37	10,613	44	9,922	29	9,857
South Bay 2	8	12,099	37	11,007	45	10,352	30	10,259
South Bay 3	13	11,880	43	10,680	51	10,062	34	9,961
South Bay 4	1	14,726	36	13,382	45	12,128	30	11,847

SYSTEM INCREMENTAL HEAT RATES

The block ***IHRs*** are sorted by increasing values for each IOU, as a simplified representation of the dispatch in the existing regulated system -- and, is therefore a representation of MC. These sorted values are shown under the heading ***IHR*** in Table C-5 series: Table C-5-PG&E for PG&E, Table C-5-SCE for SCE and Table C-5-SDG&E for SDG&E. The only restraint is that the Block order can not be violated. That is, Block 2 must be taken before Block 3, Block 3 must be taken before Block 4, and Block 4 must be taken before Block 5. Since ***IHRs*** should always have increasing values, maintaining this restraint is not a problem. Figure C-5 series show this same data graphically, along with corresponding $\boldsymbol{AHR_{AVE}}$ data which is described in the next section.

The column directly after the ***IHRs*** is the product of each MW increment and its corresponding ***IHR***, which represents the number of Btus that the units can produce in any one hour. The next column is a running sum of these products. The last column, designated "***IHR*** Cumulative" is the running sum values divided by the cumulative MWs. These ***IHR*** values are designated as the System ***IHR*** (***SIHR***). These numbers are shown in Figure series C-6, along with similar ***AHR*** data which is also described in the next section.

The ***IHR*** value at each capacity level corresponds to the system incremental heat rate, corresponding to the MC at that capacity level. The ***SIHR*** values can be thought of as an average value for all the blocks being used at that point, which corresponds to the average MC which could be expected if all blocks contributed to the marginal cost equal amounts of time.

SYSTEM AVERAGE HEAT RATES

The System $\boldsymbol{AHR_{AVE}}$, $\boldsymbol{SAHR_{AVE}}$, values are calculated similarly to ***SIHR*** but the sorting is more complex, intended to be representative of the dispatch in a competitive market with one part bidding. The $\boldsymbol{AHR_{AVE}}$ data is sorted such that blocks are taken in economic order, with the same provision that blocks can not be taken out of physical order. As it turns out, once the first block (Block 2) is taken, its upper blocks are so economic that there is no other Block 2 that can compete. Accordingly, the graphical emulation of this dispatch of heat rates, Figures C-5, show a saw tooth shape where each downward sloping arc of four blocks is a unit's heat rate curve. This is a very different shape than that of the conventional incremental heat rate curve.

The System Average Heat Rate is then calculated as the cumulative weighted average of these individual unit average heat rates. The weighting is done one block (MW) at a time. Each block $\boldsymbol{AHR_{AVE}}$ is multiplied by its corresponding incremental capacity (INC MW) to produce a ***AHR*MW*** value for the unit. This value is then added to the previous cumulative ***AHR*MW*** value to maintain a running sum. This resulting cumulative ***AHR*MW*** value is then divided by the cumulative capacity (CUM MW). This provides a running average weighted $\boldsymbol{AHR_{AVE}}$ at each point, which is the desired system $\boldsymbol{AHR_{AVE}}$. These calculations are shown in the Table C-5 series along with the corresponding ***IHR*** values described above. The corresponding graphs are shown in Figure C-6.

TABLE C-5-PG&E: PG&E SYSTEM IHR AND AHR CALCULATIONS

	SUMMARY IHR DATA									SUMMARY AHR DATA								
	PLANT	BLK #	INC MW	CUM MW	***IHR*** Btu/kWh	***IHR*MW*** UNIT	***IHR*MW*** Cumulative	***IHR*** Cumul.		PLANT	BLK #	INC MW	CUM MW	***AHR*** Btu/kWh	***AHR*MW*** UNIT	***AHR*MW*** Cumulative	***AHR*** Cumul.	***AHR/IHR*** Cumul.
1	mos7	2	135	135	7,196	971,441	971,441	7,196	1	pot3	2	5	5	10,853	54,266	54,266	10,853	1.51
2	mos6	2	135	270	7,370	994,931	1,966,372	7,283	1	pot3	3	52	57	10,207	530,763	585,029	10,264	1.41
3	mos7	3	185	455	7,890	1,459,609	3,425,981	7,530	1	pot3	4	62	119	9,689	600,716	1,185,744	9,964	1.32
4	mos6	3	185	640	8,146	1,506,925	4,932,906	7,708	1	pot3	5	41	160	9,686	397,135	1,582,880	9,893	1.28
5	pit7	3	180	820	8,476	1,525,759	6,458,665	7,876	2	hnp4	2	20	180	11,642	232,845	1,815,724	10,087	1.28
6	mos7	4	221	1,041	8,485	1,875,107	8,333,772	8,006	2	hnp4	3	82	262	10,585	867,947	2,683,671	10,243	1.28
7	con7	2	39	1,080	8,496	331,331	8,665,104	8,023	2	hnp4	4	96	358	9,985	958,544	3,642,216	10,174	1.27
8	con7	3	85	1,165	8,503	722,789	9,387,893	8,058	2	hnp4	5	66	424	9,854	650,366	4,292,582	10,124	1.26
9	pit7	2	60	1,225	8,555	513,295	9,901,188	8,083	3	mor4	2	39	463	11,694	456,063	4,748,644	10,256	1.27
10	con6	3	85	1,310	8,555	727,171	10,628,359	8,113	3	mor4	3	84	547	10,292	864,561	5,613,206	10,262	1.26
11	mos6	4	221	1,531	8,668	1,915,722	12,544,081	8,193	3	mor4	4	101	648	9,714	981,103	6,594,309	10,176	1.24
12	mor4	2	39	1,570	8,703	339,425	12,883,506	8,206	3	mor4	5	68	716	9,561	650,147	7,244,456	10,118	1.23
13	mos6	5	148	1,718	8,714	1,289,726	14,173,233	8,250	4	pit6	2	35	751	11,709	409,832	7,654,287	10,192	1.24
14	pit5	2	35	1,753	8,744	306,050	14,479,283	8,260	4	pit6	3	82	833	10,352	848,850	8,503,138	10,208	1.24
15	con6	2	39	1,792	8,756	341,490	14,820,773	8,271	4	pit6	4	97	930	9,751	945,861	9,448,999	10,160	1.23
16	mos7	5	148	1,940	8,760	1,296,414	16,117,187	8,308	4	pit6	5	65	995	9,625	625,652	10,074,650	10,125	1.22
17	pit7	4	216	2,156	8,762	1,892,651	18,009,838	8,353	5	con6	2	39	1,034	11,860	462,528	10,537,178	10,191	1.22
18	pit6	2	35	2,191	8,821	308,736	18,318,574	8,361	5	con6	3	85	1,119	10,300	875,488	11,412,666	10,199	1.22
19	mor4	3	84	2,275	8,848	743,248	19,061,822	8,379	5	con6	4	102	1,221	9,579	977,042	12,389,707	10,147	1.21
20	pit6	3	82	2,357	8,868	727,177	19,788,999	8,396	5	con6	5	68	1,289	9,479	644,582	13,034,290	10,112	1.20
21	hnp4	2	20	2,377	8,873	177,454	19,966,453	8,400	6	mor3	2	39	1,328	12,056	470,181	13,504,471	10,169	1.21
22	con6	4	102	2,479	8,877	905,452	20,871,905	8,419	6	mor3	3	84	1,412	10,616	891,770	14,396,241	10,196	1.21
23	pit5	3	82	2,561	8,900	729,832	21,601,737	8,435	6	mor3	4	101	1,513	9,950	1,004,983	15,401,224	10,179	1.21
24	pot3	3	52	2,613	8,924	464,057	22,065,793	8,445	6	mor3	5	68	1,581	9,712	660,441	16,061,665	10,159	1.20
25	con7	4	102	2,715	8,933	911,212	22,977,005	8,463	7	con7	2	39	1,620	12,112	472,386	16,534,051	10,206	1.21
26	pit3&4	3	82	2,797	8,983	736,606	23,713,611	8,478	7	con7	3	85	1,705	10,361	880,708	17,414,759	10,214	1.20
27	pit1&2	3	82	2,879	9,003	738,207	24,451,818	8,493	7	con7	4	102	1,807	9,622	981,468	18,396,228	10,181	1.20
28	hnp4	3	82	2,961	9,044	741,638	25,193,456	8,508	7	con7	5	68	1,875	9,517	647,154	19,043,382	10,156	1.19
29	mor3	2	39	3,000	9,056	353,189	25,546,644	8,516	8	pit5	2	35	1,910	12,186	426,514	19,469,896	10,194	1.20
30	mor3	3	84	3,084	9,064	761,357	26,308,001	8,530	8	pit5	3	82	1,992	10,598	869,041	20,338,937	10,210	1.20
31	pot3	2	5	3,089	9,066	45,329	26,353,330	8,531	8	pit5	4	97	2,089	9,907	960,937	21,299,874	10,196	1.20
32	pit1&2	2	20	3,109	9,079	181,571	26,534,900	8,535	8	pit5	5	65	2,154	9,712	631,257	21,931,131	10,182	1.19
33	mor4	4	101	3,210	9,083	917,368	27,452,268	8,552	9	mor1&2	2	20	2,174	12,246	244,911	22,176,042	10,201	1.19
34	mor3	4	101	3,311	9,100	919,114	28,371,382	8,569	9	mor1&2	3	82	2,256	11,128	912,503	23,088,546	10,234	1.19
35	pit6	4	97	3,408	9,135	886,120	29,257,503	8,585	9	mor1&2	4	96	2,352	10,438	1,002,050	24,090,596	10,243	1.19
36	pit5	4	97	3,505	9,135	886,132	30,143,634	8,600	9	mor1&2	5	66	2,418	10,266	677,577	24,768,173	10,243	1.19
37	mor3	5	68	3,573	9,159	622,813	30,766,448	8,611	10	pit3&4	2	20	2,438	12,905	258,107	25,026,280	10,265	1.19
38	pot3	4	62	3,635	9,276	575,101	31,341,548	8,622	10	pit3&4	3	82	2,520	11,388	933,821	25,960,101	10,302	1.19
39	pit3&4	2	20	3,655	9,276	185,523	31,527,071	8,626	10	pit3&4	4	96	2,616	10,408	999,204	26,959,305	10,306	1.19
40	mor4	5	68	3,723	9,314	633,373	32,160,444	8,638	10	pit3&4	5	66	2,682	10,341	682,485	27,641,790	10,306	1.19
41	pit5	5	65	3,788	9,344	607,366	32,767,811	8,650	11	pit7	2	60	2,742	13,001	780,062	28,421,853	10,365	1.20
42	hnp4	4	96	3,884	9,379	900,405	33,668,216	8,668	11	pit7	3	180	2,922	11,062	1,991,242	30,413,095	10,408	1.20
43	pit1&2	4	96	3,980	9,391	901,583	34,569,799	8,686	11	pit7	4	216	3,138	9,977	2,154,948	32,568,043	10,379	1.19
44	mor1&2	2	20	4,000	9,407	188,135	34,757,933	8,689	11	pit7	5	144	3,282	9,705	1,397,580	33,965,623	10,349	1.19
45	mor1&2	3	82	4,082	9,441	774,202	35,532,135	8,705	12	mos7	2	135	3,417	13,304	1,796,095	35,761,718	10,466	1.20
46	pit7	5	144	4,226	9,469	1,363,571	36,895,706	8,731	12	mos7	3	185	3,602	9,758	1,805,199	37,566,917	10,429	1.19
47	pit3&4	4	96	4,322	9,529	914,759	37,810,465	8,748	12	mos7	4	221	3,823	9,079	2,006,352	39,573,269	10,351	1.18
48	pit6	5	65	4,387	9,579	622,617	38,433,082	8,761	12	mos7	5	148	3,971	8,949	1,324,404	40,897,673	10,299	1.18
49	mor1&2	4	96	4,483	9,675	928,783	39,361,865	8,780	13	mos6	2	135	4,106	13,370	1,804,959	42,702,632	10,400	1.18
50	hnp4	5	66	4,549	9,724	641,751	40,003,616	8,794	13	mos6	3	185	4,291	9,918	1,834,901	44,537,533	10,379	1.18
51	con7	5	68	4,617	9,754	663,242	40,666,858	8,808	13	mos6	4	221	4,512	9,273	2,049,296	46,586,829	10,325	1.17
52	con6	5	68	4,685	9,811	667,170	41,334,028	8,823	13	mos6	5	148	4,660	9,115	1,349,026	47,935,854	10,287	1.17
53	hnp3	2	17	4,702	9,876	167,886	41,501,914	8,826	14	pit1&2	2	20	4,680	13,412	268,231	48,204,085	10,300	1.17
54	mor1&2	5	66	4,768	10,081	665,338	42,167,252	8,844	14	pit1&2	3	82	4,762	11,673	957,189	49,161,274	10,324	1.17
55	pit1&2	5	66	4,834	10,331	681,813	42,849,065	8,864	14	pit1&2	4	96	4,858	10,573	1,014,964	50,176,237	10,329	1.17
56	pot3	5	41	4,875	10,341	423,968	43,273,033	8,877	14	pit1&2	5	66	4,924	10,339	682,388	50,858,625	10,329	1.16
57	hnp2	2	17	4,892	10,364	176,181	43,449,214	8,882	15	hnp3	2	17	4,941	16,339	277,769	51,136,394	10,349	1.17
58	hmb1&2	3	27	4,919	10,366	279,882	43,729,097	8,890	15	hnp3	3	27	4,968	12,974	350,302	51,486,696	10,364	1.17
59	hmb1&2	2	16	4,935	10,543	168,689	43,897,786	8,895	15	hnp3	4	32	5,000	12,336	394,742	51,881,438	10,376	1.17
60	hnp3	3	27	4,962	10,861	293,239	44,191,025	8,906	15	hnp3	5	21	5,021	12,471	261,888	52,143,326	10,385	1.17
61	hnp2	3	27	4,989	10,981	296,490	44,487,515	8,917	16	hmb1&2	2	16	5,037	16,853	269,651	52,412,977	10,406	1.17
62	pit3&4	5	66	5,055	11,211	739,944	45,227,459	8,947	16	hmb1&2	3	27	5,064	13,245	357,616	52,770,593	10,421	1.16
63	hmb1&2	4	31	5,086	11,392	353,140	45,580,599	8,962	16	hmb1&2	4	31	5,095	12,142	376,412	53,147,005	10,431	1.16
64	hnp2	4	32	5,118	11,861	379,557	45,960,156	8,980	16	hmb1&2	5	21	5,116	12,167	255,499	53,402,504	10,438	1.16
65	hnp3	4	32	5,150	12,246	391,877	46,352,033	9,000	17	hnp2	2	17	5,133	16,865	286,706	53,689,210	10,460	1.16
66	hnp2	5	21	5,171	12,701	266,719	46,618,751	9,015	17	hnp2	3	27	5,160	13,382	361,311	54,050,521	10,475	1.16
67	hmb1&2	5	21	5,192	13,521	283,948	46,902,700	9,034	17	hnp2	4	32	5,192	12,517	400,547	54,451,068	10,487	1.16
68	hnp3	5	21	5,213	13,552	284,586	47,187,286	9,052	17	hnp2	5	21	5,213	12,433	261,103	54,712,171	10,495	1.16

TABLE C-5-SCE: SCE SYSTEM IHR AND AHR CALCULATIONS

	SUMMARY IHR DATA										SUMMARY AHR DATA								
	PLANT	BLK #	INC MW	*IHR* Btu/kWh	CUM MW	*IHR*MW* UNIT	*IHR*MW* Cumulative	*IHR* Cumul.		PLANT	BLK #	INC MW	*AHR* Btu/kWh	CUM MW	*AHR*MW* UNIT	*AHR*MW* Cumulative	*AHR* Cumul.	*AHR/IHR* Cumul.
1	cw34	2	40	7,013	40	280,515	280,515	7,013	1	orb1	2	120	10,354	120	1,242,460	1,242,460	10,354	1.48
2	cw34	3	60	7,064	100	423,843	704,358	7,044	1	orb1	3	130	9,753	250	1,267,892	2,510,352	10,041	1.43
3	cw34	4	140	7,334	240	1,026,818	1,731,177	7,213	1	orb1	4	120	9,486	370	1,138,317	3,648,669	9,861	1.37
4	hig3&4	2	14	7,899	254	110,589	1,841,766	7,251	1	orb1	5	130	9,382	500	1,219,663	4,868,332	9,737	1.34
5	cw34	5	132	8,018	386	1,058,398	2,900,164	7,513	2	ala5&6	2	160	10,532	660	1,685,114	6,553,446	9,929	1.32
6	hig3&4	3	26	8,096	412	210,501	3,110,665	7,550	2	ala5&6	3	180	9,810	840	1,765,810	8,319,256	9,904	1.31
7	ala5&6	2	160	8,155	572	1,304,836	4,415,501	7,719	2	ala5&6	4	180	9,560	1,020	1,720,773	10,040,029	9,843	1.28
8	orb1	2	120	8,171	692	980,508	5,396,009	7,798	2	ala5&6	5	180	9,491	1,200	1,708,324	11,748,353	9,790	1.26
9	orb2	2	175	8,192	867	1,433,628	6,829,637	7,877	3	red7&8	2	100	10,808	1,300	1,080,843	12,829,196	9,869	1.25
10	hig3&4	4	30	8,338	897	250,148	7,079,785	7,893	3	red7&8	3	300	9,995	1,600	2,998,470	15,827,666	9,892	1.25
11	els3&4	2	120	8,395	1,017	1,007,398	8,087,183	7,952	3	red7&8	4	140	9,633	1,740	1,348,586	17,176,252	9,871	1.24
12	hig1&2	2	10	8,413	1,027	84,135	8,171,318	7,956	3	red7&8	5	160	9,548	1,900	1,527,641	18,703,893	9,844	1.24
13	orb1	3	130	8,429	1,157	1,095,717	9,267,035	8,010	4	cw01	2	13	11,259	1,913	146,369	18,850,262	9,854	1.23
14	eti3&4	2	120	8,438	1,277	1,012,529	10,279,564	8,050	4	cw01	3	13	10,587	1,926	137,631	18,987,893	9,859	1.22
15	hig1&2	3	20	8,438	1,297	168,768	10,448,332	8,056	4	cw01	4	13	10,343	1,939	134,456	19,122,349	9,862	1.22
16	man1&2	2	100	8,443	1,397	844,270	11,292,602	8,083	4	cw01	5	9	10,264	1,948	92,374	19,214,723	9,864	1.22
17	ala3&4	2	120	8,443	1,517	1,013,150	12,305,752	8,112	5	cw02	2	16	11,401	1,964	182,415	19,397,138	9,876	1.22
18	orb2	3	175	8,459	1,692	1,480,332	13,786,084	8,148	5	cw02	3	16	10,650	1,980	170,402	19,567,541	9,883	1.21
19	hig1&2	4	18	8,471	1,710	152,474	13,938,558	8,151	5	cw02	4	16	10,370	1,996	165,923	19,733,464	9,887	1.21
20	hig3&4	5	9	8,485	1,719	76,365	14,014,923	8,153	5	cw02	5	14	10,262	2,010	143,666	19,877,130	9,889	1.21
21	hig1&2	5	10	8,495	1,729	84,951	14,099,874	8,155	6	lbc8&9	2	110	11,404	2,120	1,254,487	21,131,618	9,968	1.22
22	hun1&2	2	100	8,552	1,829	855,242	14,955,116	8,177	6	lbc8&9	3	120	10,506	2,240	1,260,742	22,392,360	9,997	1.22
23	red7&8	2	100	8,557	1,929	855,746	15,810,862	8,196	6	lbc8&9	4	110	10,230	2,350	1,125,296	23,517,655	10,008	1.22
24	els3&4	3	160	8,576	2,089	1,372,124	17,182,986	8,225	6	lbc8&9	5	150	10,107	2,500	1,516,118	25,033,773	10,014	1.22
25	ala3&4	3	160	8,639	2,249	1,382,232	18,565,218	8,255	7	man1&2	2	100	12,114	2,600	1,211,366	26,245,140	10,094	1.22
26	eti3&4	3	160	8,641	2,409	1,382,483	19,947,700	8,280	7	man1&2	3	105	10,087	2,705	1,059,098	27,304,238	10,094	1.22
27	ala5&6	3	180	8,656	2,589	1,558,076	21,505,776	8,307	7	man1&2	4	95	9,706	2,800	922,045	28,226,283	10,081	1.21
28	sbr1&2	2	28	8,681	2,617	243,056	21,748,832	8,311	7	man1&2	5	90	9,664	2,890	869,785	29,096,067	10,068	1.21
29	orb1	4	120	8,742	2,737	1,049,016	22,797,847	8,330	8	hun1&2	2	100	12,570	2,990	1,256,984	30,353,051	10,152	1.22
30	red7&8	3	300	8,759	3,037	2,627,705	25,425,553	8,372	8	hun1&2	3	100	10,331	3,090	1,033,061	31,386,112	10,157	1.21
31	hun1&2	3	100	8,768	3,137	876,842	26,302,395	8,385	8	hun1&2	4	100	9,822	3,190	982,224	32,368,336	10,147	1.21
32	man1&2	3	105	8,799	3,242	923,941	27,226,335	8,398	8	hun1&2	5	90	9,666	3,280	869,928	33,238,264	10,134	1.21
33	orb2	4	175	8,818	3,417	1,543,113	28,769,448	8,420	9	orb2	2	175	13,188	3,455	2,307,837	35,546,102	10,288	1.22
34	els3&4	4	160	8,839	3,577	1,414,195	30,183,643	8,438	9	orb2	3	175	10,168	3,630	1,779,318	37,325,420	10,282	1.22
35	ala3&4	4	160	8,933	3,737	1,429,341	31,612,984	8,459	9	orb2	4	175	9,595	3,805	1,679,122	39,004,542	10,251	1.21
36	eti3&4	4	160	8,943	3,897	1,430,826	33,043,810	8,479	9	orb2	5	175	9,442	3,980	1,652,347	40,656,889	10,215	1.20
37	red5&6	2	70	8,992	3,967	629,452	33,673,262	8,488	10	cw34	2	40	13,307	4,020	532,296	41,189,186	10,246	1.21
38	red7&8	4	140	9,028	4,107	1,263,956	34,937,218	8,507	10	cw34	3	60	11,822	4,080	709,297	41,898,483	10,269	1.21
39	hun1&2	4	100	9,050	4,207	905,042	35,842,260	8,520	10	cw34	4	140	10,361	4,220	1,450,505	43,348,988	10,272	1.21
40	sbr1&2	3	28	9,056	4,235	253,562	36,095,822	8,523	10	cw34	5	132	9,506	4,352	1,254,776	44,603,764	10,249	1.20
41	ala5&6	4	180	9,074	4,415	1,633,296	37,729,117	8,546	11	eti3&4	2	120	15,141	4,472	1,816,911	46,420,675	10,380	1.21
42	orb1	5	130	9,112	4,545	1,184,559	38,913,677	8,562	11	eti3&4	3	160	11,005	4,632	1,760,748	48,181,424	10,402	1.21
43	ala1&2	2	70	9,127	4,615	638,866	39,552,542	8,570	11	eti3&4	4	160	10,078	4,792	1,612,465	49,793,888	10,391	1.21
44	red5&6	3	90	9,134	4,705	822,033	40,374,575	8,581	11	eti3&4	5	160	9,798	4,952	1,567,706	51,361,595	10,372	1.21
45	els3&4	5	190	9,198	4,895	1,747,566	42,122,141	8,605	12	els3&4	2	120	15,882	5,072	1,905,889	53,267,484	10,502	1.22
46	els1&2	2	70	9,224	4,965	645,700	42,767,841	8,614	12	els3&4	3	160	11,251	5,232	1,800,080	55,067,564	10,525	1.22
47	red7&8	5	160	9,248	5,125	1,479,652	44,247,493	8,634	12	els3&4	4	160	10,188	5,392	1,630,072	56,697,636	10,515	1.22
48	eti1&2	2	60	9,264	5,185	555,834	44,803,327	8,641	12	els3&4	5	190	9,825	5,582	1,866,701	58,564,337	10,492	1.21
49	orb2	5	175	9,268	5,360	1,621,972	46,425,299	8,661	13	ala3&4	2	120	16,210	5,702	1,945,196	60,509,533	10,612	1.23
50	man1&2	4	95	9,279	5,455	881,550	47,306,849	8,672	13	ala3&4	3	160	11,407	5,862	1,825,110	62,334,643	10,634	1.23
51	ala3&4	5	160	9,305	5,615	1,488,738	48,795,587	8,690	13	ala3&4	4	160	10,311	6,022	1,649,777	63,984,420	10,625	1.22
52	cw01	2	13	9,320	5,628	121,160	48,916,747	8,692	13	ala3&4	5	160	9,960	6,182	1,593,579	65,577,999	10,608	1.22
53	eti3&4	5	160	9,322	5,788	1,491,457	50,408,203	8,709	14	eti1&2	2	60	16,432	6,242	985,907	66,563,907	10,664	1.22
54	red5&6	4	90	9,324	5,878	839,196	51,247,400	8,719	14	eti1&2	3	60	12,244	6,302	734,610	67,298,517	10,679	1.22
55	ala1&2	3	90	9,341	5,968	840,686	52,088,086	8,728	14	eti1&2	4	60	11,371	6,362	682,273	67,980,790	10,685	1.22
56	cw02	2	16	9,368	5,984	149,892	52,237,979	8,730	14	eti1&2	5	64	11,106	6,426	710,761	68,691,551	10,690	1.22
57	ala5&6	5	180	9,375	6,164	1,687,520	53,925,499	8,748	15	els1&2	2	70	17,208	6,496	1,204,540	69,896,091	10,760	1.23
58	hun1&2	5	90	9,379	6,254	844,104	54,769,602	8,758	15	els1&2	3	90	12,131	6,586	1,091,829	70,987,920	10,779	1.23
59	sbr1&2	4	28	9,384	6,282	262,764	55,032,367	8,760	15	els1&2	4	90	11,038	6,676	993,454	71,981,374	10,782	1.23
60	els1&2	3	90	9,394	6,372	845,487	55,877,854	8,769	15	els1&2	5	80	10,678	6,756	854,229	72,835,602	10,781	1.23

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TABLE C-5-SCE: SCE SYSTEM IHR AND AHR CALCULATIONS - CONTINUED

	SUMMARY IHR DATA									SUMMARY AHR DATA									
	PLANT	BLK #	INC MW	***IHR*** Btu/kWh	CUM MW	***IHR*MW*** UNIT	***IHR*MW*** Cumulative	***IHR*** Cum.		PLANT	BLK #	INC MW	***AHR*** Btu/kWh	CUM MW	***AHR*MW*** UNIT	***AHR*MW*** Cumulative	***AHR*** Cumul.	***AHR/IHR*** Cumul.
61	red5&6	5	80	9,535	6,452	762,837	56,640,691	8,779	16	ala1&2	2	70	17,605	6,826	1,232,347	74,067,949	10,851	1.24
62	cw02	3	16	9,540	6,468	152,635	56,793,326	8,781	16	ala1&2	3	90	12,222	6,916	1,099,983	75,167,933	10,869	1.24
63	cw01	3	13	9,549	6,481	124,142	56,917,468	8,782	16	ala1&2	4	90	11,084	7,006	997,572	76,165,504	10,871	1.24
64	lbc8&9	2	110	9,608	6,591	1,056,887	57,974,354	8,796	16	ala1&2	5	80	10,734	7,086	858,733	77,024,237	10,870	1.24
65	eti1&2	3	60	9,627	6,651	577,613	58,551,967	8,803	17	red5&6	2	70	18,702	7,156	1,309,127	78,333,364	10,947	1.24
66	els1&2	4	90	9,631	6,741	866,751	59,418,718	8,815	17	red5&6	3	90	12,511	7,246	1,125,960	79,459,324	10,966	1.24
67	lbc8&9	3	120	9,647	6,861	1,157,626	60,576,344	8,829	17	red5&6	4	90	11,144	7,336	1,002,955	80,462,279	10,968	1.24
68	ala1&2	4	90	9,663	6,951	869,675	61,446,019	8,840	17	red5&6	5	80	10,661	7,416	852,893	81,315,172	10,965	1.24
69	sbr1&2	5	28	9,667	6,979	270,663	61,716,682	8,843	18	sbr1&2	2	28	18,968	7,444	531,107	81,846,279	10,995	1.24
70	lbc8&9	4	110	9,717	7,089	1,068,869	62,785,550	8,857	18	sbr1&2	3	28	13,553	7,472	379,489	82,225,769	11,005	1.24
71	cw02	4	16	9,742	7,105	155,877	62,941,427	8,859	18	sbr1&2	4	28	12,072	7,500	338,005	82,563,773	11,009	1.24
72	cw01	4	13	9,808	7,118	127,510	63,068,937	8,860	18	sbr1&2	5	28	11,426	7,528	319,940	82,883,714	11,010	1.24
73	lbc8&9	5	150	9,836	7,268	1,475,363	64,544,300	8,881	19	hig1&2	2	10	34,940	7,538	349,396	83,233,109	11,042	1.24
74	man1&2	5	90	9,842	7,358	885,739	65,430,039	8,892	19	hig1&2	3	20	20,641	7,558	412,821	83,645,930	11,067	1.24
75	els1&2	5	80	9,898	7,438	791,833	66,221,872	8,903	19	hig1&2	4	18	15,481	7,576	278,651	83,924,581	11,078	1.24
76	cw02	5	14	9,960	7,452	139,444	66,361,316	8,905	19	hig1&2	5	10	13,820	7,586	138,196	84,062,777	11,081	1.24
77	ala1&2	5	80	10,047	7,532	803,745	67,165,061	8,917	20	hig3&4	2	14	44,598	7,600	624,373	84,687,150	11,143	1.25
78	cw01	5	9	10,050	7,541	90,452	67,255,513	8,919	20	hig3&4	3	26	24,520	7,626	637,514	85,324,663	11,189	1.25
79	eti1&2	4	60	10,104	7,601	606,260	67,861,772	8,928	20	hig3&4	4	30	17,262	7,656	517,867	85,842,530	11,212	1.26
80	eti1&2	5	64	10,719	7,665	685,992	68,547,765	8,943	20	hig3&4	5	9	15,100	7,665	135,898	85,978,428	11,217	1.25

TABLE C-5-SDG&E: SDG&E SYSTEM IHR AND AHR CALCULATIONS

	SUMMARY IHR DATA									SUMMARY AHR DATA									
	PLANT	BLK #	INC MW	CUM MW	***IHR*** Btu/kWh	***IHR*MW*** UNIT	***IHR*MW*** Cumul.	***IHR*** Cumul.		PLANT	BLK #	INC MW	CUM MW	***AHR*** Btu/kWh	***AHR*MW*** UNIT	***AHR*MW*** Cumulative	***AHR*** Cumul.	***AHR/IHR*** Cumul.
1	sba1	2	7	7	8,560	59,923	59,923	8,560	1	sba1	2	7	7	11,778	82,446	82,446	11,778	1.38
2	sba1	3	37	44	8,764	324,271	384,194	8,732	1	sba1	3	37	44	10,613	392,666	475,112	10,798	1.24
3	sba3	2	13	57	8,937	116,177	500,371	8,778	1	sba1	4	44	88	9,922	436,553	911,665	10,360	1.18
4	enc5	2	59	116	9,016	531,917	1,032,288	8,899	1	sba1	5	29	117	9,857	285,863	1,197,528	10,235	1.15
5	sba3	3	43	159	9,082	390,525	1,422,813	8,949	2	sba3	2	13	130	11,880	154,440	1,351,968	10,400	1.16
6	sba2	2	8	167	9,127	73,019	1,495,832	8,957	2	sba3	3	43	173	10,680	459,244	1,811,212	10,469	1.17
7	enc5	3	79	246	9,190	725,985	2,221,817	9,032	2	sba3	4	51	224	10,062	513,141	2,324,353	10,377	1.15
8	sba2	3	37	283	9,287	343,637	2,565,454	9,065	2	sba3	5	34	258	9,961	338,664	2,663,017	10,322	1.14
9	sba1	4	44	327	9,368	412,176	2,977,630	9,106	3	sba2	2	8	266	12,099	96,795	2,759,812	10,375	1.14
10	enc3	2	8	335	9,374	74,995	3,052,625	9,112	3	sba2	3	37	303	11,007	407,264	3,167,077	10,452	1.15
11	enc4	2	53	388	9,472	502,013	3,554,638	9,161	3	sba2	4	45	348	10,352	465,856	3,632,933	10,439	1.14
12	sba3	4	51	439	9,487	483,825	4,038,464	9,199	3	sba2	5	30	378	10,259	307,762	3,940,695	10,425	1.13
13	enc5	4	94	533	9,605	902,838	4,941,301	9,271	4	enc1	2	7	385	12,632	88,422	4,029,117	10,465	1.13
14	enc4	3	74	607	9,617	711,654	5,652,955	9,313	4	enc1	3	27	412	11,483	310,038	4,339,155	10,532	1.13
15	enc3	3	27	634	9,635	260,155	5,913,110	9,327	4	enc1	4	32	444	10,831	346,586	4,685,741	10,553	1.13
16	enc1	2	7	641	9,736	68,155	5,981,265	9,331	4	enc1	5	21	465	10,737	225,480	4,911,221	10,562	1.13
17	enc2	2	6	647	9,763	58,577	6,039,842	9,335	5	enc3	2	8	473	13,155	105,243	5,016,464	10,606	1.14
18	sba2	4	45	692	9,763	439,331	6,479,174	9,363	5	enc3	3	27	500	11,675	315,230	5,331,694	10,663	1.14
19	enc1	3	27	719	9,815	265,009	6,744,183	9,380	5	enc3	4	33	533	10,933	360,797	5,692,491	10,680	1.14
20	enc2	3	26	745	9,889	257,107	7,001,290	9,398	5	enc3	5	22	555	10,891	239,600	5,932,091	10,688	1.14
21	enc4	4	87	832	9,966	867,054	7,868,344	9,457	6	enc4	2	53	608	13,472	714,007	6,646,098	10,931	1.16
22	sba3	5	34	866	10,027	340,914	8,209,258	9,480	6	enc4	3	74	682	11,055	818,074	7,464,172	10,945	1.15
23	enc5	5	63	929	10,163	640,257	8,849,515	9,526	6	enc4	4	87	769	10,494	912,936	8,377,108	10,894	1.14
24	sba1	5	29	958	10,169	294,911	9,144,426	9,545	6	enc4	5	59	828	10,398	613,474	8,990,582	10,858	1.14
25	enc1	4	32	990	10,231	327,393	9,471,819	9,567	7	enc5	2	59	887	13,485	795,593	9,786,176	11,033	1.15
26	enc2	4	31	1,021	10,258	318,009	9,789,828	9,588	7	enc5	3	79	966	10,741	848,535	10,634,711	11,009	1.15
27	sba4	3	36	1,057	10,268	369,663	10,159,491	9,612	7	enc5	4	94	1,060	10,144	953,543	11,588,254	10,932	1.14
28	sba4	2	1	1,058	10,278	10,278	10,169,769	9,612	7	enc5	5	63	1,123	10,055	633,474	12,221,728	10,883	1.13
29	enc3	4	33	1,091	10,375	342,383	10,512,151	9,635	8	enc2	2	6	1,129	14,131	84,783	12,306,511	10,900	1.13
30	sba2	5	30	1,121	10,407	312,208	10,824,359	9,656	8	enc2	3	26	1,155	12,451	323,726	12,630,237	10,935	1.13
31	enc4	5	59	1,180	10,437	615,781	11,440,141	9,695	8	enc2	4	31	1,186	11,406	353,600	12,983,837	10,948	1.13
32	sba4	4	45	1,225	10,741	483,358	11,923,498	9,733	8	enc2	5	21	1,207	11,135	233,841	13,217,677	10,951	1.13
33	enc2	5	21	1,246	10,760	225,956	12,149,455	9,751	9	sba4	2	1	1,208	14,726	14,726	13,232,404	10,954	1.12
34	enc1	5	21	1,267	10,909	229,081	12,378,536	9,770	9	sba4	3	36	1,244	13,382	481,746	13,714,149	11,024	1.13
35	enc3	5	22	1,289	11,377	250,290	12,628,826	9,797	9	sba4	4	45	1,289	12,128	545,765	14,259,914	11,063	1.13
36	sba4	5	30	1,319	11,797	353,905	12,982,730	9,843	9	sba4	5	30	1,319	11,847	355,406	14,615,320	11,081	1.13

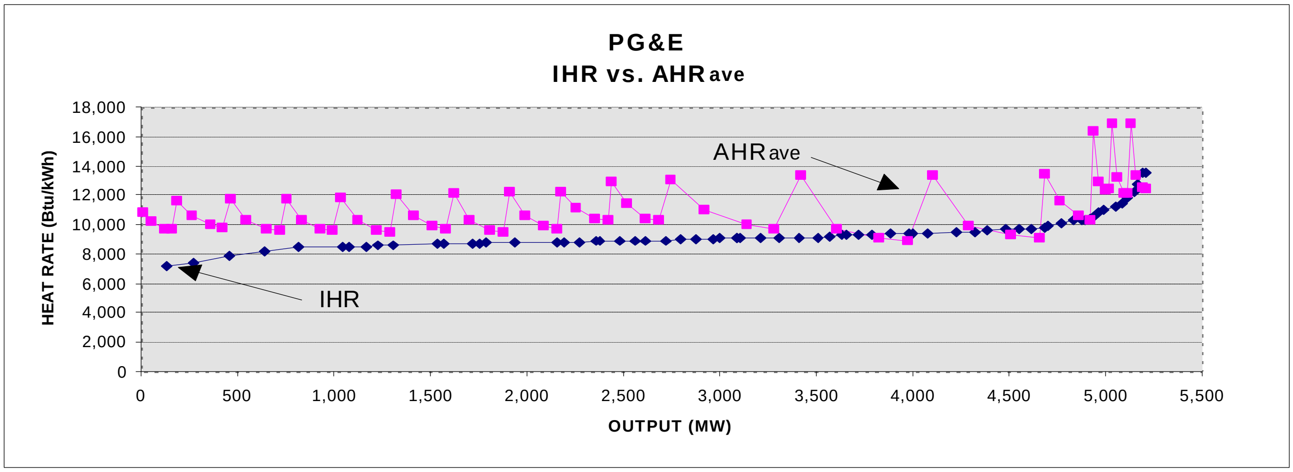

Figure C-5-PG&E

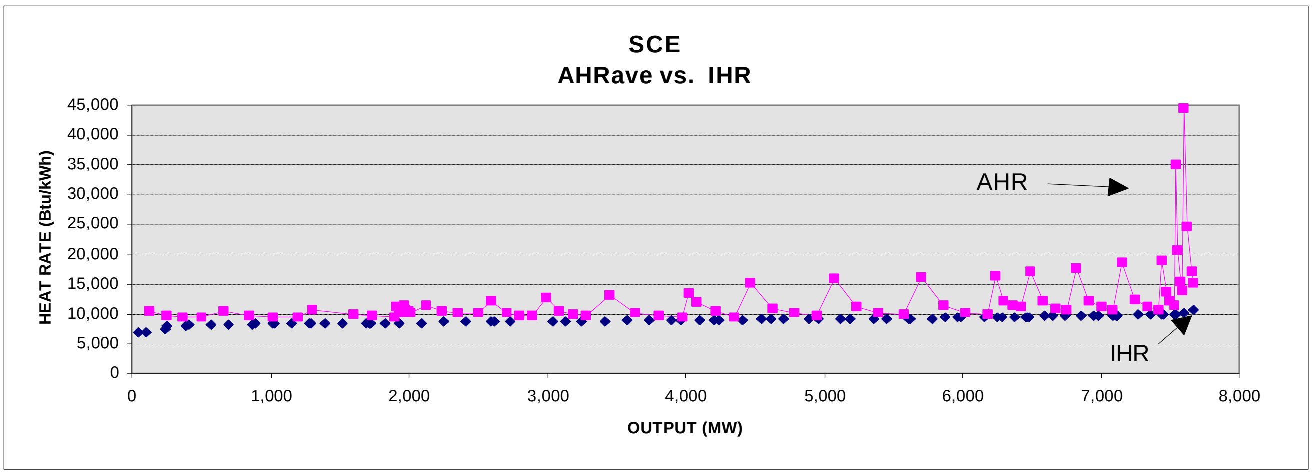

Figure C-5-SCE

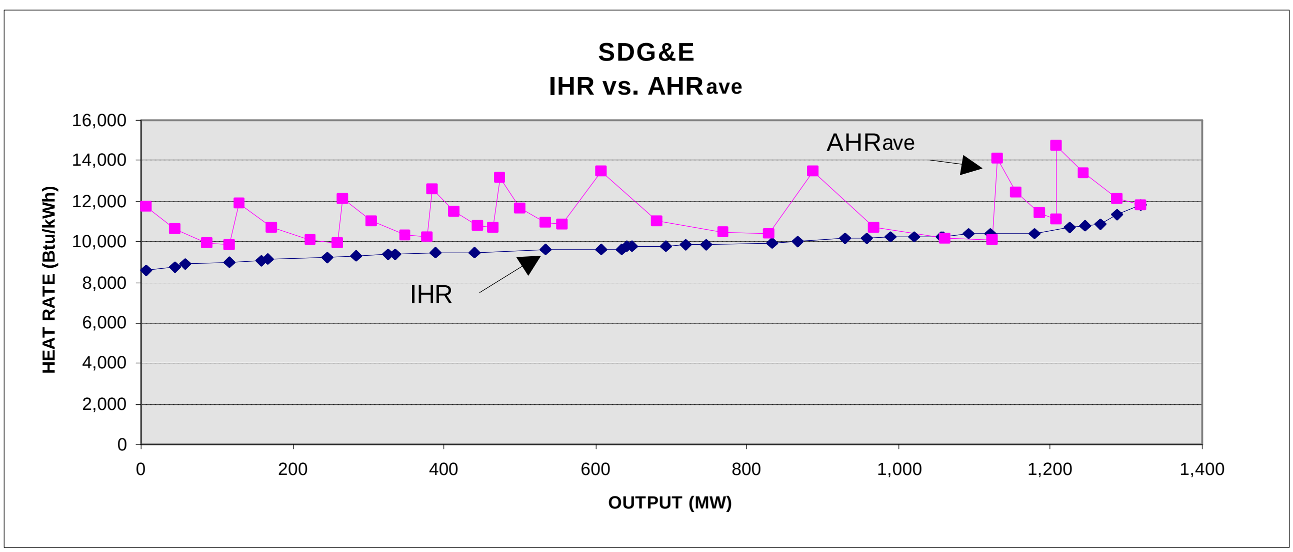

Figure C-5-SDG&E

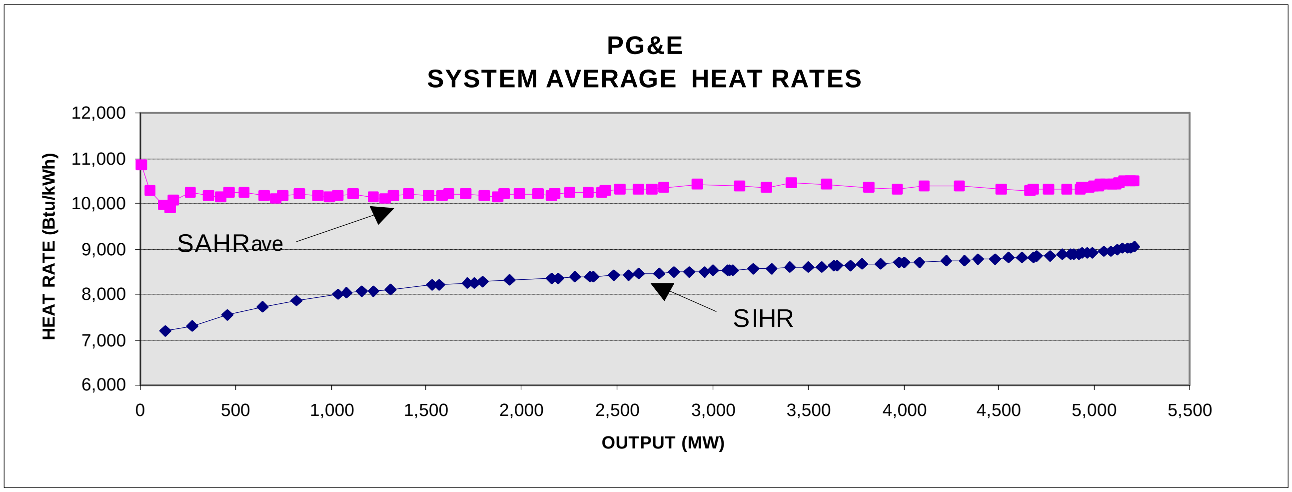

Figure C-6-PG&E

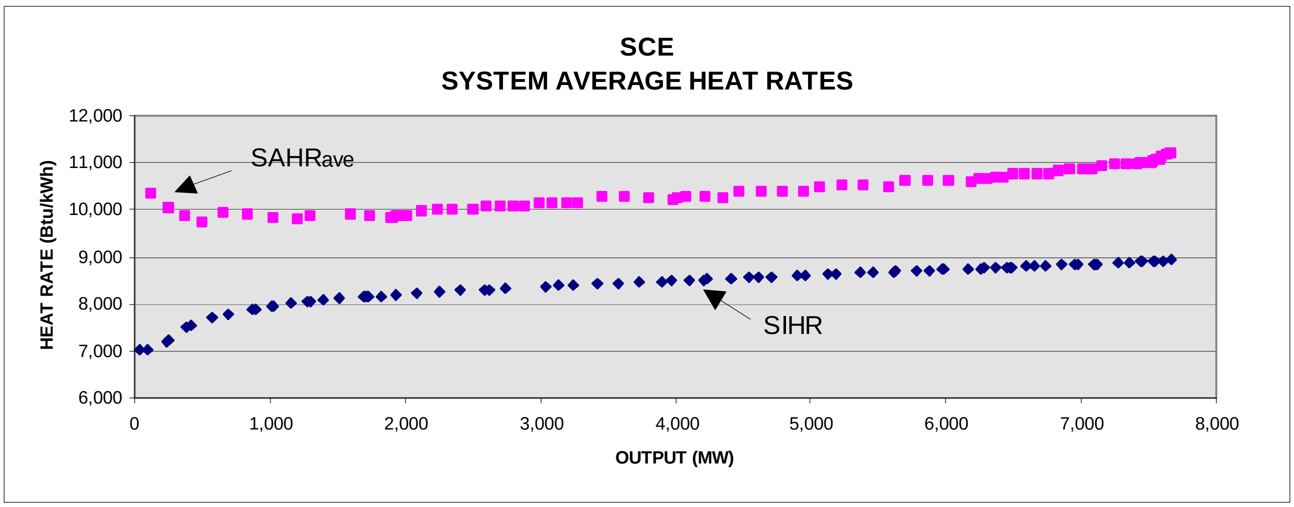

Figure C-6-SCE

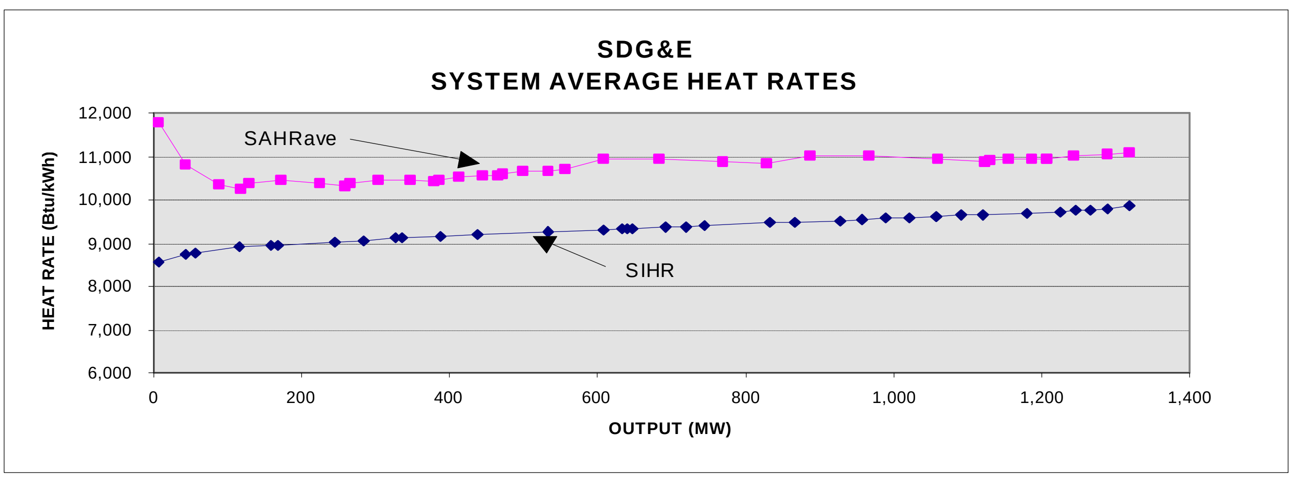

Figure C-6-SDG&E

SYSTEM COSTS

The System Costs are calculated as the ***SIHRs*** and the ***SAHR$_{AVE}$s*** times the relevant fuel costs. SCE must be handled differently as it has two gas prices: one for the Cool Water units and another for the other SCE units. The Cool Water gas price is significantly lower than SCE's general gas price, which gives the Cool Water units a considerable economic advantage raising them higher up in the economic dispatch order.

The Table C-6 series, on the next page, gives the cost calculations for each of the three IOUs. Table C-7 gives the cost calculations for the three IOUs combined into a single system -- a proxy for the PX. Figures C-7 and C-8 give the corresponding graphical representations.

Table C-8, below, summarizes the final values in Tables C-6 and C-7. It is these values which can be used to characterize the systems, as will be explained in the next section.

TABLE C-8: SUMMARY OF VALUES FOR 1998

	PG&E	SCE	SDG&E	AVERAGE
SIHR HEAT RATE (Btu/kWh)	9,052	8,943	9,843	9,067
SAHR HEAT RATE (Btu/kWh)	10,495	11,217	11,081	10,939
MC - Dispatch Gas Price ($/MWh)	18.4	22.6	21.9	21.0
MC - Total Gas Price ($/MWh)	22.6	22.8	28.2	23.3
MCP - Dispatch Gas Price ($/MWh)	21.3	28.3	24.6	25.4
MCP - Total Gas Price ($/MWh)	26.2	28.6	31.7	28.0

If one elects to make the assumption that it is these final values which characterize the IOUs system individually and as a whole, then the heat rates and unit cost values of Table C-8 can be thought of as characterizing the respective systems.

Furthermore, the IOU "MC-Dispatch Gas Price" values can be considered to be proxy values for each IOUs MC in a single-area simulation, such as Elfin. And the "AVERAGE" value could be considered as a state wide value if these three IOUs were combined into one data set.

Similarly, the "MCP-Total Gas Price" values can be considered to be proxy values for MCP: PG&E for Northern California (Zone 3) and an average of SCE and SDG&E for southern California (Zone 4). The "AVERAGE" value can be considered as a state-wide MCP.

Using these two sets of data one can get a feeling for the relative costs of dispatch in the regulated market relative to the deregulated market. Whereas, the deregulated market is represented by an average dispatch cost of 21 $/MWh, the average MCP cost is estimated as 28 $/MWh, 33 percent higher. The 33 percent estimate ignores other factors in the market, particularly the effect of out-of-state resources. Based on various UPLAN runs, this 33 percent would apply about 70 - 75 percent of the time. Using 75 percent of 33 percent translates to 25 percent which closely correlates with our Table 4 calculations.

TABLE C-6-PG&E: PG&E SYSTEM AVERAGE COST CALCULATIONS

SUMMARY IHR DATA										SUMMARY AHR DATA									
PLANT	BLK #	INC MW	CUM MW	*IHR* Btu/kWh	*IHR*MW* Block	Cumul.	*AVER IHR*	Disp. *2.03* $/MWh	Total *2.5* $/MWh	PLANT	BLK #	INC MW	CUM MW	*AHR* Btu/kWh	*AHR*MW* Block	Cumul.	*AVER AHR*	Disp. *2.03* $/MWh	Total *2.5* $/MWh
mos7	2	135	135	7,196	971441	971441	7,196	14.6	18.0	pot3	2	5	5	10,853		54266	10,853	22.0	27.1
mos6	2	135	270	7,370	994931	1966372	7,283	14.8	18.2	pot3	3	52	57	10,207	530763	585029	10,264	20.8	25.7
mos7	3	185	455	7,890	1459609	3425981	7,530	15.3	18.8	pot3	4	62	119	9,689	600716	1185744	9,964	20.2	24.9
mos6	3	185	640	8,146	1506925	4932906	7,708	15.6	19.3	pot3	5	41	160	9,686	397135	1582880	9,893	20.1	24.7
pit7	3	180	820	8,476	1525759	6458665	7,876	16.0	19.7	hnp4	2	20	180	11,642	232845	1815724	10,087	20.5	25.2
mos7	4	221	1041	8,485	1875107	8333772	8,006	16.3	20.0	hnp4	3	82	262	10,585	867947	2683671	10,243	20.8	25.6
con7	2	39	1080	8,496	331331	8665104	8,023	16.3	20.1	hnp4	4	96	358	9,985	958544	3642216	10,174	20.7	25.4
con7	3	85	1165	8,503	722789	9387893	8,058	16.4	20.1	hnp4	5	66	424	9,854	650366	4292582	10,124	20.6	25.3
pit7	2	60	1225	8,555	513295	9901188	8,083	16.4	20.2	mor4	2	39	463	11,694	456063	4748644	10,256	20.8	25.6
con6	3	85	1310	8,555	727171	10628359	8,113	16.5	20.3	mor4	3	84	547	10,292	864561	5613206	10,262	20.8	25.7
mos6	4	221	1531	8,668	1915722	12544081	8,193	16.6	20.5	mor4	4	101	648	9,714	981103	6594309	10,176	20.7	25.4
mor4	2	39	1570	8,703	339425	12883506	8,206	16.7	20.5	mor4	5	68	716	9,561	650147	7244456	10,118	20.5	25.3
mos6	5	148	1718	8,714	1289726	14173233	8,250	16.7	20.6	pit6	2	35	751	11,709	409832	7654287	10,192	20.7	25.5
pit5	2	35	1753	8,744	306050	14479283	8,260	16.8	20.6	pit6	3	82	833	10,352	848850	8503138	10,208	20.7	25.5
con6	2	39	1792	8,756	341490	14820773	8,271	16.8	20.7	pit6	4	97	930	9,751	945861	9448999	10,160	20.6	25.4
mos7	5	148	1940	8,760	1296414	16117187	8,308	16.9	20.8	pit6	5	65	995	9,625	625652	10074650	10,125	20.6	25.3
pit7	4	216	2156	8,762	1892651	18009838	8,353	17.0	20.9	con6	2	39	1034	11,860	462528	10537178	10,191	20.7	25.5
pit6	2	35	2191	8,821	308736	18318574	8,361	17.0	20.9	con6	3	85	1119	10,300	875488	11412666	10,199	20.7	25.5
mor4	3	84	2275	8,848	743248	19061822	8,379	17.0	20.9	con6	4	102	1221	9,579	977042	12389707	10,147	20.6	25.4
pit6	3	82	2357	8,868	727177	19788999	8,396	17.0	21.0	con6	5	68	1289	9,479	644582	13034290	10,112	20.5	25.3
hnp4	2	20	2377	8,873	177454	19966453	8,400	17.1	21.0	mor3	2	39	1328	12,056	470181	13504471	10,169	20.6	25.4
con6	4	102	2479	8,877	905452	20871905	8,419	17.1	21.0	mor3	3	84	1412	10,616	891770	14396241	10,196	20.7	25.5
pit5	3	82	2561	8,900	729832	21601737	8,435	17.1	21.1	mor3	4	101	1513	9,950	1004983	15401224	10,179	20.7	25.4
pot3	3	52	2613	8,924	464057	22065793	8,445	17.1	21.1	mor3	5	68	1581	9,712	660441	16061665	10,159	20.6	25.4
con7	4	102	2715	8,933	911212	22977005	8,463	17.2	21.2	con7	2	39	1620	12,112	472386	16534051	10,206	20.7	25.5
pit3&4	3	82	2797	8,983	736606	23713611	8,478	17.2	21.2	con7	3	85	1705	10,361	880708	17414759	10,214	20.7	25.5
pit1&2	3	82	2879	9,003	738207	24451818	8,493	17.2	21.2	con7	4	102	1807	9,622	981468	18396228	10,181	20.7	25.5
hnp4	3	82	2961	9,044	741638	25193456	8,508	17.3	21.3	con7	5	68	1875	9,517	647154	19043382	10,156	20.6	25.4
mor3	2	39	3000	9,056	353189	25546644	8,516	17.3	21.3	pit5	2	35	1910	12,186	426514	19469896	10,194	20.7	25.5
mor3	3	84	3084	9,064	761357	26308001	8,530	17.3	21.3	pit5	3	82	1992	10,598	869041	20338937	10,210	20.7	25.5
pot3	2	5	3089	9,066	45329	26353330	8,531	17.3	21.3	pit5	4	97	2089	9,907	960937	21299874	10,196	20.7	25.5
pit1&2	2	20	3109	9,079	181571	26534900	8,535	17.3	21.3	pit5	5	65	2154	9,712	631257	21931131	10,182	20.7	25.5
mor4	4	101	3210	9,083	917368	27452268	8,552	17.4	21.4	mor1&2	2	20	2174	12,246	244911	22176042	10,201	20.7	25.5
mor3	4	101	3311	9,100	919114	28371382	8,569	17.4	21.4	mor1&2	3	82	2256	11,128	912503	23088546	10,234	20.8	25.6
pit6	4	97	3408	9,135	886120	29257503	8,585	17.4	21.5	mor1&2	4	96	2352	10,438	1002050	24090596	10,243	20.8	25.6
pit5	4	97	3505	9,135	886132	30143634	8,600	17.5	21.5	mor1&2	5	66	2418	10,266	677577	24768173	10,243	20.8	25.6
mor3	5	68	3573	9,159	622813	30766448	8,611	17.5	21.5	pit3&4	2	20	2438	12,905	258107	25026280	10,265	20.8	25.7
pot3	4	62	3635	9,276	575101	31341548	8,622	17.5	21.6	pit3&4	3	82	2520	11,388	933821	25960101	10,302	20.9	25.8
pit3&4	2	20	3655	9,276	185523	31527071	8,626	17.5	21.6	pit3&4	4	96	2616	10,408	999204	26959305	10,306	20.9	25.8
mor4	5	68	3723	9,314	633373	32160444	8,638	17.5	21.6	pit3&4	5	66	2682	10,341	682485	27641790	10,306	20.9	25.8
pit5	5	65	3788	9,344	607366	32767811	8,650	17.6	21.6	pit7	2	60	2742	13,001	780062	28421853	10,365	21.0	25.9
hnp4	4	96	3884	9,379	900405	33668216	8,668	17.6	21.7	pit7	3	180	2922	11,062	1991242	30413095	10,408	21.1	26.0
pit1&2	4	96	3980	9,391	901583	34569799	8,686	17.6	21.7	pit7	4	216	3138	9,977	2154948	32568043	10,379	21.1	25.9
mor1&2	2	20	4000	9,407	188135	34757933	8,689	17.6	21.7	pit7	5	144	3282	9,705	1397580	33965623	10,349	21.0	25.9
mor1&2	3	82	4082	9,441	774202	35532135	8,705	17.7	21.8	mos7	2	135	3417	13,304	1796095	35761718	10,466	21.2	26.2
pit7	5	144	4226	9,469	1363571	36895706	8,731	17.7	21.8	mos7	3	185	3602	9,758	1805199	37566917	10,429	21.2	26.1
pit3&4	4	96	4322	9,529	914759	37810465	8,748	17.8	21.9	mos7	4	221	3823	9,079	2006352	39573269	10,351	21.0	25.9
pit6	5	65	4387	9,579	622617	38433082	8,761	17.8	21.9	mos7	5	148	3971	8,949	1324404	40897673	10,299	20.9	25.7
mor1&2	4	96	4483	9,675	928783	39361865	8,780	17.8	22.0	mos6	2	135	4106	13,370	1804959	42702632	10,400	21.1	26.0
hnp4	5	66	4549	9,724	641751	40003616	8,794	17.9	22.0	mos6	3	185	4291	9,918	1834901	44537533	10,379	21.1	25.9
con7	5	68	4617	9,754	663242	40666858	8,808	17.9	22.0	mos6	4	221	4512	9,273	2049296	46586829	10,325	21.0	25.8
con6	5	68	4685	9,811	667170	41334028	8,823	17.9	22.1	mos6	5	148	4660	9,115	1349026	47935854	10,287	20.9	25.7
hnp3	2	17	4702	9,876	167886	41501914	8,826	17.9	22.1	pit1&2	2	20	4680	13,412	268231	48204085	10,300	20.9	25.8
mor1&2	5	66	4768	10,081	665338	42167252	8,844	18.0	22.1	pit1&2	3	82	4762	11,673	957189	49161274	10,324	21.0	25.8
pit1&2	5	66	4834	10,331	681813	42849065	8,864	18.0	22.2	pit1&2	4	96	4858	10,573	1014964	50176237	10,329	21.0	25.8
pot3	5	41	4875	10,341	423968	43273033	8,877	18.0	22.2	pit1&2	5	66	4924	10,339	682388	50858625	10,329	21.0	25.8
hnp2	2	17	4892	10,364	176181	43449214	8,882	18.0	22.2	hnp3	2	17	4941	16,339	277769	51136394	10,349	21.0	25.9
hmb1&2	3	27	4919	10,366	279882	43729097	8,890	18.0	22.2	hnp3	3	27	4968	12,974	350302	51486696	10,364	21.0	25.9
hmb1&2	2	16	4935	10,543	168689	43897786	8,895	18.1	22.2	hnp3	4	32	5000	12,336	394742	51881438	10,376	21.1	25.9
hnp3	3	27	4962	10,861	293239	44191025	8,906	18.1	22.3	hnp3	5	21	5021	12,471	261888	52143326	10,385	21.1	26.0
hnp2	3	27	4989	10,981	296490	44487515	8,917	18.1	22.3	hmb1&2	2	16	5037	16,853	269651	52412977	10,406	21.1	26.0
pit3&4	5	66	5055	11,211	739944	45227459	8,947	18.2	22.4	hmb1&2	3	27	5064	13,245	357616	52770593	10,421	21.2	26.1
hmb1&2	4	31	5086	11,392	353140	45580599	8,962	18.2	22.4	hmb1&2	4	31	5095	12,142	376412	53147005	10,431	21.2	26.1
hnp2	4	32	5118	11,861	379557	45960156	8,980	18.2	22.5	hmb1&2	5	21	5116	12,167	255499	53402504	10,438	21.2	26.1
hnp3	4	32	5150	12,246	391877	46352033	9,000	18.3	22.5	hnp2	2	17	5133	16,865	286706	53689210	10,460	21.2	26.1
hnp2	5	21	5171	12,701	266719	46618751	9,015	18.3	22.5	hnp2	3	27	5160	13,382	361311	54050521	10,475	21.3	26.2
hmb1&2	5	21	5192	13,521	283948	46902700	9,034	18.3	22.6	hnp2	4	32	5192	12,517	400547	54451068	10,487	21.3	26.2
hnp3	5	21	5213	13,552	284586	47187286	9,052	18.4	22.6	hnp2	5	21	5213	12,433	261103	54712171	10,495	21.3	26.2

TABLE C-6-SCE: SCE SYSTEM AVERAGE COST CALCULATIONS

SUMMARY IHR DATA

PLANT	BLK #	INC MW	*IHR* Btu/kWh	CUM MW	DISPATCH *Unit Cost * MW* Unit	DISPATCH *Unit Cost * MW* Cumul.	TOTAL *Unit Cost * MW* Unit	TOTAL *Unit Cost * MW* Cumul.	Disp. *1.59* *2.27* $/MWh	Total *1.98* *2.27* $/MWh
cw34	2	40	7,013	40	468	468	592	592	11.7	14.8
cw34	3	60	7,064	100	708	1,176	894	1,486	11.8	14.9
cw34	4	140	7,334	240	1,715	2,891	2,167	3,653	12.0	15.2
cw34	5	132	8,018	372	1,768	4,659	2,233	5,886	12.5	15.8
cw01	2	13	9,320	385	202	4,861	256	6,142	12.6	16.0
cw02	2	16	9,368	401	250	5,111	316	6,458	12.7	16.1
cw02	3	16	9,540	417	255	5,366	322	6,780	12.9	16.3
cw01	3	13	9,549	430	207	5,573	262	7,042	13.0	16.4
cw02	4	16	9,742	446	260	5,834	329	7,371	13.1	16.5
cw01	4	13	9,808	459	213	6,047	269	7,640	13.2	16.6
cw02	5	14	9,960	473	233	6,280	294	7,934	13.3	16.8
cw01	5	9	10,050	482	151	6,431	191	8,125	13.3	16.9
hig3&4	2	14	7,899	496	285	6,716	285	8,410	13.5	17.0
hig3&4	3	26	8,096	522	543	7,259	543	8,953	13.9	17.2
ala5&6	2	160	8,155	682	3,366	10,626	3,366	12,320	15.6	18.1
orb1	2	120	8,171	802	2,530	13,155	2,530	14,850	16.4	18.5
orb2	2	175	8,192	977	3,699	16,854	3,699	18,548	17.3	19.0
hig3&4	4	30	8,338	1007	645	17,499	645	19,194	17.4	19.1
els3&4	2	120	8,395	1127	2,599	20,098	2,599	21,793	17.8	19.3
hig1&2	2	10	8,413	1137	217	20,316	217	22,010	17.9	19.4
orb1	3	130	8,429	1267	2,827	23,142	2,827	24,837	18.3	19.6
eti3&4	2	120	8,438	1387	2,612	25,755	2,612	27,449	18.6	19.8
hig1&2	3	20	8,438	1407	435	26,190	435	27,885	18.6	19.8
man1&2	2	100	8,443	1507	2,178	28,368	2,178	30,063	18.8	19.9
ala3&4	2	120	8,443	1627	2,614	30,982	2,614	32,677	19.0	20.1
orb2	3	175	8,459	1802	3,819	34,802	3,819	36,496	19.3	20.3
hig1&2	4	18	8,471	1820	393	35,195	393	36,889	19.3	20.3
hig3&4	5	9	8,485	1829	197	35,392	197	37,086	19.4	20.3
hig1&2	5	10	8,495	1839	219	35,611	219	37,306	19.4	20.3
hun1&2	2	100	8,552	1939	2,207	37,818	2,207	39,512	19.5	20.4
red7&8	2	100	8,557	2039	2,208	40,026	2,208	41,720	19.6	20.5
els3&4	3	160	8,576	2199	3,540	43,566	3,540	45,260	19.8	20.6
ala3&4	3	160	8,639	2359	3,566	47,132	3,566	48,826	20.0	20.7
eti3&4	3	160	8,641	2519	3,567	50,699	3,567	52,393	20.1	20.8
ala5&6	3	180	8,656	2699	4,020	54,718	4,020	56,413	20.3	20.9
sbr1&2	2	28	8,681	2727	627	55,346	627	57,040	20.3	20.9
orb1	4	120	8,742	2847	2,706	58,052	2,706	59,746	20.4	21.0
red7&8	3	300	8,759	3147	6,779	64,831	6,779	66,526	20.6	21.1
hun1&2	3	100	8,768	3247	2,262	67,094	2,262	68,788	20.7	21.2
man1&2	3	105	8,799	3352	2,384	69,477	2,384	71,172	20.7	21.2
orb2	4	175	8,818	3527	3,981	73,459	3,981	75,153	20.8	21.3
els3&4	4	160	8,839	3687	3,649	77,107	3,649	78,802	20.9	21.4
ala3&4	4	160	8,933	3847	3,688	80,795	3,688	82,489	21.0	21.4
eti3&4	4	160	8,943	4007	3,692	84,487	3,692	86,181	21.1	21.5
red5&6	2	70	8,992	4077	1,624	86,111	1,624	87,805	21.1	21.5
red7&8	4	140	9,028	4217	3,261	89,372	3,261	91,066	21.2	21.6
hun1&2	4	100	9,050	4317	2,335	91,707	2,335	93,401	21.2	21.6
sbr1&2	3	28	9,056	4345	654	92,361	654	94,055	21.3	21.6
ala5&6	4	180	9,074	4525	4,214	96,575	4,214	98,269	21.3	21.7
orb1	5	130	9,112	4655	3,056	99,631	3,056	101,325	21.4	21.8
ala1&2	2	70	9,127	4725	1,648	101,279	1,648	102,973	21.4	21.8
red5&6	3	90	9,134	4815	2,121	103,400	2,121	105,094	21.5	21.8
els3&4	5	190	9,198	5005	4,509	107,909	4,509	109,603	21.6	21.9
els1&2	2	70	9,224	5075	1,666	109,575	1,666	111,269	21.6	21.9
red7&8	5	160	9,248	5235	3,818	113,392	3,818	115,086	21.7	22.0
eti1&2	2	60	9,264	5295	1,434	114,826	1,434	116,520	21.7	22.0
orb2	5	175	9,268	5470	4,185	119,011	4,185	120,705	21.8	22.1
man1&2	4	95	9,279	5565	2,274	121,285	2,274	122,980	21.8	22.1
ala3&4	5	160	9,305	5725	3,841	125,126	3,841	126,820	21.9	22.2
eti3&4	5	160	9,322	5885	3,848	128,974	3,848	130,668	21.9	22.2

=Cool Water

SUMMARY AHR DATA

PLANT	BLK #	INC MW	*AHR* Btu/kWh	CUM MW	DISPATCH *Unit Cost * MW* Unit	DISPATCH *Unit Cost * MW* Cumul.	TOTAL *Unit Cost * MW* Unit	TOTAL *Unit Cost * MW* Cumul.	Disp. *1.67* *2.58* $/MWh	Total *2.11* *2.58* $/MWh
cw01	2	13	11,259	13	244	244	309	309	18.8	23.8
cw01	3	13	10,587	26	230	474	290	599	18.2	23.0
cw01	4	13	10,343	39	225	699	284	883	17.9	22.6
cw01	5	9	10,264	48	154	853	195	1,078	17.8	22.5
cw02	2	16	11,401	64	305	1,158	385	1,463	18.1	22.9
cw02	3	16	10,650	80	285	1,442	360	1,822	18.0	22.8
cw02	4	16	10,370	96	277	1,719	350	2,172	17.9	22.6
cw02	5	14	10,262	110	240	1,959	303	2,476	17.8	22.5
orb1	2	120	10,354	230	3,206	5,165	3,206	5,681	22.5	24.7
orb1	3	130	9,753	360	3,271	8,436	3,271	8,952	23.4	24.9
orb1	4	120	9,486	480	2,937	11,373	2,937	11,889	23.7	24.8
orb1	5	130	9,382	610	3,147	14,520	3,147	15,036	23.8	24.6
ala5&6	2	160	10,532	770	4,348	18,867	4,348	19,383	24.5	25.2
ala5&6	3	180	9,810	950	4,556	23,423	4,556	23,939	24.7	25.2
ala5&6	4	180	9,560	1,130	4,440	27,863	4,440	28,379	24.7	25.1
ala5&6	5	180	9,491	1,310	4,407	32,270	4,407	32,786	24.6	25.0
red7&8	2	100	10,808	1,410	2,789	35,059	2,789	35,575	24.9	25.2
red7&8	3	300	9,995	1,710	7,736	42,795	7,736	43,311	25.0	25.3
red7&8	4	140	9,633	1,850	3,479	46,274	3,479	46,790	25.0	25.3
red7&8	5	160	9,548	2,010	3,941	50,215	3,941	50,732	25.0	25.2
cw34	2	40	13,307	2,050	889	51,104	1,123	51,855	24.9	25.3
cw34	3	60	11,822	2,110	1,185	52,289	1,497	53,351	24.8	25.3
cw34	4	140	10,361	2,250	2,422	54,711	3,061	56,412	24.3	25.1
cw34	5	132	9,506	2,382	2,095	56,807	2,648	59,059	23.8	24.8
lbc8&9	2	110	11,404	2,492	3,237	60,043	3,237	62,296	24.1	25.0
lbc8&9	3	120	10,506	2,612	3,253	63,296	3,253	65,549	24.2	25.1
lbc8&9	4	110	10,230	2,722	2,903	66,199	2,903	68,452	24.3	25.1
lbc8&9	5	150	10,107	2,872	3,912	70,111	3,912	72,364	24.4	25.2
man1&	2	100	12,114	2,972	3,125	73,236	3,125	75,489	24.6	25.4
man1&	3	105	10,087	3,077	2,732	75,969	2,732	78,221	24.7	25.4
man1&	4	95	9,706	3,172	2,379	78,347	2,379	80,600	24.7	25.4
man1&	5	90	9,664	3,262	2,244	80,591	2,244	82,844	24.7	25.4
hun1&2	2	100	12,570	3,362	3,243	83,835	3,243	86,087	24.9	25.6
hun1&2	3	100	10,331	3,462	2,665	86,500	2,665	88,753	25.0	25.6
hun1&2	4	100	9,822	3,562	2,534	89,034	2,534	91,287	25.0	25.6
hun1&2	5	90	9,666	3,652	2,244	91,278	2,244	93,531	25.0	25.6
orb2	2	175	13,188	3,827	5,954	97,233	5,954	99,485	25.4	26.0
orb2	3	175	10,168	4,002	4,591	101,823	4,591	104,076	25.4	26.0
orb2	4	175	9,595	4,177	4,332	106,155	4,332	108,408	25.4	26.0
orb2	5	175	9,442	4,352	4,263	110,418	4,263	112,671	25.4	25.9
eti3&4	2	120	15,141	4,472	4,688	115,106	4,688	117,359	25.7	26.2
eti3&4	3	160	11,005	4,632	4,543	119,649	4,543	121,902	25.8	26.3
eti3&4	4	160	10,078	4,792	4,160	123,809	4,160	126,062	25.8	26.3
eti3&4	5	160	9,798	4,952	4,045	127,854	4,045	130,106	25.8	26.3
els3&4	2	120	15,882	5,072	4,917	132,771	4,917	135,024	26.2	26.6
els3&4	3	160	11,251	5,232	4,644	137,415	4,644	139,668	26.3	26.7
els3&4	4	160	10,188	5,392	4,206	141,621	4,206	143,873	26.3	26.7
els3&4	5	190	9,825	5,582	4,816	146,437	4,816	148,690	26.2	26.6
ala3&4	2	120	16,210	5,702	5,019	151,455	5,019	153,708	26.6	27.0
ala3&4	3	160	11,407	5,862	4,709	156,164	4,709	158,417	26.6	27.0
ala3&4	4	160	10,311	6,022	4,256	160,421	4,256	162,673	26.6	27.0
ala3&4	5	160	9,960	6,182	4,111	164,532	4,111	166,785	26.6	27.0
eti1&2	2	60	16,432	6,242	2,544	167,076	2,544	169,328	26.8	27.1
eti1&2	3	60	12,244	6,302	1,895	168,971	1,895	171,224	26.8	27.2
eti1&2	4	60	11,371	6,362	1,760	170,731	1,760	172,984	26.8	27.2
eti1&2	5	64	11,106	6,426	1,834	172,565	1,834	174,818	26.9	27.2
els1&2	2	70	17,208	6,496	3,108	175,673	3,108	177,925	27.0	27.4
els1&2	3	90	12,131	6,586	2,817	178,490	2,817	180,742	27.1	27.4
els1&2	4	90	11,038	6,676	2,563	181,053	2,563	183,305	27.1	27.5
els1&2	5	80	10,678	6,756	2,204	183,257	2,204	185,509	27.1	27.5

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TABLE C-6-SCE: SCE SYSTEM AVERAGE COST CALCULATIONS - CONTINUED

SUMMARY IHR DATA											SUMMARY AHR DATA										
PLANT	BLK #	INC MW	*IHR* Btu/kWh	CUM MW	DISPATCH Unit Cost * MW Unit	DISPATCH Unit Cost * MW Cumul.	TOTAL Unit Cost * MW Unit	TOTAL Unit Cost * MW Cumul.	*Disp. 1.59 2.27* $/MWh	*Total 1.98 2.27* $/MWh	= Cool Water PLANT	BLK #	INC MW	*AHR* Btu/kWh	CUM MW	DISPATCH Unit Cost * MW Unit	DISPATCH Unit Cost * MW Cumul.	TOTAL Unit Cost * MW Unit	TOTAL Unit Cost * MW Cumul.	*Disp. 1.59 2.27* $/MWh	*Total 1.98 2.27* $/MWh
red5&6	4	90	9,324	90	2,165	2,165	2,165	2,165	24.1	24.1	ala1&2	2	70	17,605	70	3,179	3,179	3,179	3,179	45.4	45.4
ala1&2	3	90	9,341	180	2,169	4,334	2,169	4,334	24.1	24.1	ala1&2	3	90	12,222	160	2,838	6,017	2,838	6,017	37.6	37.6
ala5&6	5	180	9,375	360	4,354	8,688	4,354	8,688	24.1	24.1	ala1&2	4	90	11,084	250	2,574	8,591	2,574	8,591	34.4	34.4
hun1&2	5	90	9,379	450	2,178	10,866	2,178	10,866	24.1	24.1	ala1&2	5	80	10,734	330	2,216	10,807	2,216	10,807	32.7	32.7
sbr1&2	4	28	9,384	478	678	11,544	678	11,544	24.1	24.1	red5&6	2	70	18,702	400	3,378	14,184	3,378	14,184	35.5	35.5
els1&2	3	90	9,394	568	2,181	13,725	2,181	13,725	24.2	24.2	red5&6	3	90	12,511	490	2,905	17,089	2,905	17,089	34.9	34.9
red5&6	5	80	9,535	648	1,968	15,693	1,968	15,693	24.2	24.2	red5&6	4	90	11,144	580	2,588	19,677	2,588	19,677	33.9	33.9
lbc8&9	2	110	9,608	758	2,727	18,420	2,727	18,420	24.3	24.3	red5&6	5	80	10,661	660	2,200	21,877	2,200	21,877	33.1	33.1
eti1&2	3	60	9,627	818	1,490	19,910	1,490	19,910	24.3	24.3	sbr1&2	2	28	18,968	688	1,370	23,248	1,370	23,248	33.8	33.8
els1&2	4	90	9,631	908	2,236	22,146	2,236	22,146	24.4	24.4	sbr1&2	3	28	13,553	716	979	24,227	979	24,227	33.8	33.8
lbc8&9	3	120	9,647	1028	2,987	25,133	2,987	25,133	24.4	24.4	sbr1&2	4	28	12,072	744	872	25,099	872	25,099	33.7	33.7
ala1&2	4	90	9,663	1118	2,244	27,377	2,244	27,377	24.5	24.5	sbr1&2	5	28	11,426	772	825	25,924	825	25,924	33.6	33.6
sbr1&2	5	28	9,667	1146	698	28,075	698	28,075	24.5	24.5	hig1&2	2	10	34,940	782	901	26,826	901	26,826	34.3	34.3
lbc8&9	4	110	9,717	1256	2,758	30,833	2,758	30,833	24.5	24.5	hig1&2	3	20	20,641	802	1,065	27,891	1,065	27,891	34.8	34.8
lbc8&9	5	150	9,836	1406	3,806	34,639	3,806	34,639	24.6	24.6	hig1&2	4	18	15,481	820	719	28,610	719	28,610	34.9	34.9
man1&2	5	90	9,842	1496	2,285	36,924	2,285	36,924	24.7	24.7	hig1&2	5	10	13,820	830	357	28,966	357	28,966	34.9	34.9
els1&2	5	80	9,898	1576	2,043	38,967	2,043	38,967	24.7	24.7	hig3&4	2	14	44,598	844	1,611	30,577	1,611	30,577	36.2	36.2
ala1&2	5	80	10,047	1656	2,074	41,041	2,074	41,041	24.8	24.8	hig3&4	3	26	24,520	870	1,645	32,222	1,645	32,222	37.0	37.0
eti1&2	4	60	10,104	1716	1,564	42,605	1,564	42,605	24.8	24.8	hig3&4	4	30	17,262	900	1,336	33,558	1,336	33,558	37.3	37.3
eti1&2	5	64	10,719	1780	1,770	44,375	1,770	44,375	24.9	24.9	hig3&4	5	9	15,100	909	351	33,908	351	33,908	37.3	37.3

TABLE C-6-SDG&E: SDG&E SYSTEM AVERAGE COST CALCULATIONS

SUMMARY IHR DATA										SUMMARY AHR DATA									
PLANT	BLK #	INC MW	CUM MW	*IHR* Btu/kWh	*IHR*MW* Block	*IHR*MW* Cumul.	*AVER IHR*	Disp. *2.22* $/MWh	Total *2.86* $/MWh	PLANT	BLK #	INC MW	CUM MW	*AHR* Btu/kWh	*AHR*MW* Block	*AHR*MW* Cumul.	*AVER AHR*	Disp. *2.22* $/MWh	Total *2.86* $/MWh
sba1	2	7	7	8,560	59923	59923	8,560	19.0	24.5	sba1	2	7	7	11,778	82446	82446	11,778	26.1	33.7
sba1	3	37	44	8,764	324271	384194	8,732	19.4	25.0	sba1	3	37	44	10,613	392666	475112	10,798	24.0	30.9
sba3	2	13	57	8,937	116177	500371	8,778	19.5	25.1	sba1	4	44	88	9,922	436553	911665	10,360	23.0	29.6
enc5	2	59	116	9,016	531917	1032288	8,899	19.8	25.5	sba1	5	29	117	9,857	285863	1197528	10,235	22.7	29.3
sba3	3	43	159	9,082	390525	1422813	8,949	19.9	25.6	sba3	2	13	130	11,880	154440	1351968	10,400	23.1	29.7
sba2	2	8	167	9,127	73019	1495832	8,957	19.9	25.6	sba3	3	43	173	10,680	459244	1811212	10,469	23.2	29.9
enc5	3	79	246	9,190	725985	2221817	9,032	20.1	25.8	sba3	4	51	224	10,062	513141	2324353	10,377	23.0	29.7
sba2	3	37	283	9,287	343637	2565454	9,065	20.1	25.9	sba3	5	34	258	9,961	338664	2663017	10,322	22.9	29.5
sba1	4	44	327	9,368	412176	2977630	9,106	20.2	26.0	sba2	2	8	266	12,099	96795	2759812	10,375	23.0	29.7
enc3	2	8	335	9,374	74995	3052625	9,112	20.2	26.1	sba2	3	37	303	11,007	407264	3167077	10,452	23.2	29.9
enc4	2	53	388	9,472	502013	3554638	9,161	20.3	26.2	sba2	4	45	348	10,352	465856	3632933	10,439	23.2	29.9
sba3	4	51	439	9,487	483825	4038464	9,199	20.4	26.3	sba2	5	30	378	10,259	307762	3940695	10,425	23.1	29.8
enc5	4	94	533	9,605	902838	4941301	9,271	20.6	26.5	enc1	2	7	385	12,632	88422	4029117	10,465	23.2	29.9
enc4	3	74	607	9,617	711654	5652955	9,313	20.7	26.6	enc1	3	27	412	11,483	310038	4339155	10,532	23.4	30.1
enc3	3	27	634	9,635	260155	5913110	9,327	20.7	26.7	enc1	4	32	444	10,831	346586	4685741	10,553	23.4	30.2
enc1	2	7	641	9,736	68155	5981265	9,331	20.7	26.7	enc1	5	21	465	10,737	225480	4911221	10,562	23.4	30.2
enc2	2	6	647	9,763	58577	6039842	9,335	20.7	26.7	enc3	2	8	473	13,155	105243	5016464	10,606	23.5	30.3
sba2	4	45	692	9,763	439331	6479174	9,363	20.8	26.8	enc3	3	27	500	11,675	315230	5331694	10,663	23.7	30.5
enc1	3	27	719	9,815	265009	6744183	9,380	20.8	26.8	enc3	4	33	533	10,933	360797	5692491	10,680	23.7	30.5
enc2	3	26	745	9,889	257107	7001290	9,398	20.9	26.9	enc3	5	22	555	10,891	239600	5932091	10,688	23.7	30.6
enc4	4	87	832	9,966	867054	7868344	9,457	21.0	27.0	enc4	2	53	608	13,472	714007	6646098	10,931	24.3	31.3
sba3	5	34	866	10,027	340914	8209258	9,480	21.0	27.1	enc4	3	74	682	11,055	818074	7464172	10,945	24.3	31.3
enc5	5	63	929	10,163	640257	8849515	9,526	21.1	27.2	enc4	4	87	769	10,494	912936	8377108	10,894	24.2	31.2
sba1	5	29	958	10,169	294911	9144426	9,545	21.2	27.3	enc4	5	59	828	10,398	613474	8990582	10,858	24.1	31.1
enc1	4	32	990	10,231	327393	9471819	9,567	21.2	27.4	enc5	2	59	887	13,485	795593	9786176	11,033	24.5	31.6
enc2	4	31	1021	10,258	318009	9789828	9,588	21.3	27.4	enc5	3	79	966	10,741	848535	10634711	11,009	24.4	31.5
sba4	3	36	1057	10,268	369663	10159491	9,612	21.3	27.5	enc5	4	94	1060	10,144	953543	11588254	10,932	24.3	31.3
sba4	2	1	1058	10,278	10278	10169769	9,612	21.3	27.5	enc5	5	63	1123	10,055	633474	12221728	10,883	24.2	31.1
enc3	4	33	1091	10,375	342383	10512151	9,635	21.4	27.6	enc2	2	6	1129	14,131	84783	12306511	10,900	24.2	31.2
sba2	5	30	1121	10,407	312208	10824359	9,656	21.4	27.6	enc2	3	26	1155	12,451	323726	12630237	10,935	24.3	31.3
enc4	5	59	1180	10,437	615781	11440141	9,695	21.5	27.7	enc2	4	31	1186	11,406	353600	12983837	10,948	24.3	31.3
sba4	4	45	1225	10,741	483358	11923498	9,733	21.6	27.8	enc2	5	21	1207	11,135	233841	13217677	10,951	24.3	31.3
enc2	5	21	1246	10,760	225956	12149455	9,751	21.6	27.9	sba4	2	1	1208	14,726	14726	13232404	10,954	24.3	31.3
enc1	5	21	1267	10,909	229081	12378536	9,770	21.7	27.9	sba4	3	36	1244	13,382	481746	13714149	11,024	24.5	31.5
enc3	5	22	1289	11,377	250290	12628826	9,797	21.8	28.0	sba4	4	45	1289	12,128	545765	14259914	11,063	24.6	31.6
sba4	5	30	1319	11,797	353905	12982730	9,843	21.9	28.2	sba4	5	30	1319	11,847	355406	14615320	11,081	24.6	31.7

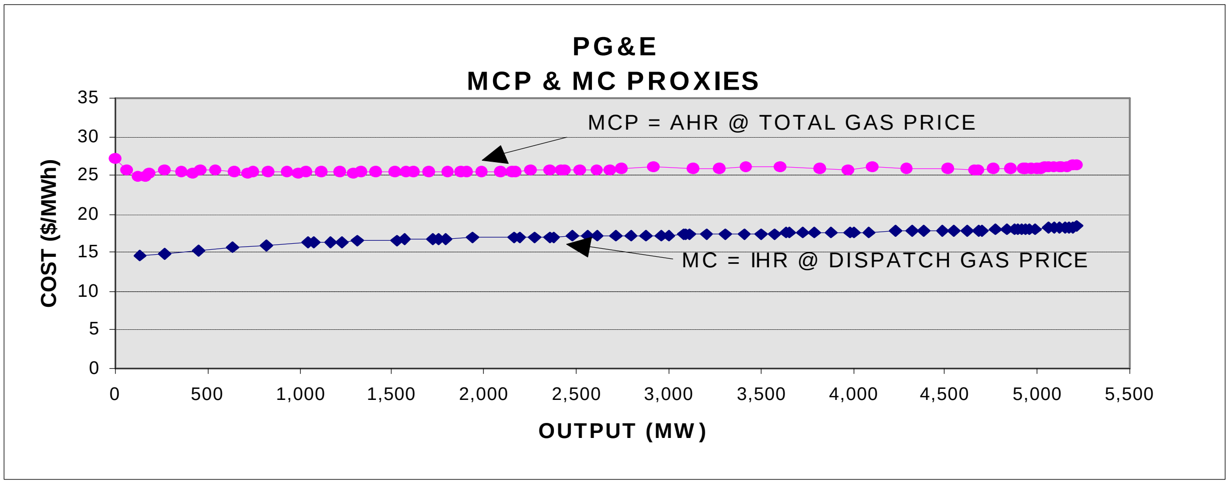

Figure C-7-PG&E

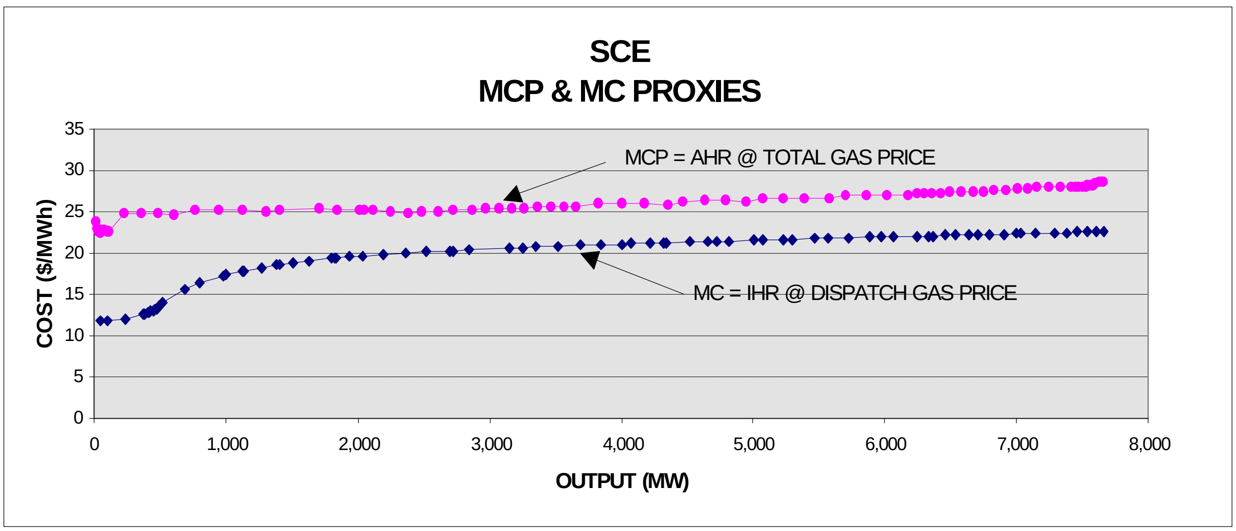

Figure C-7-SCE

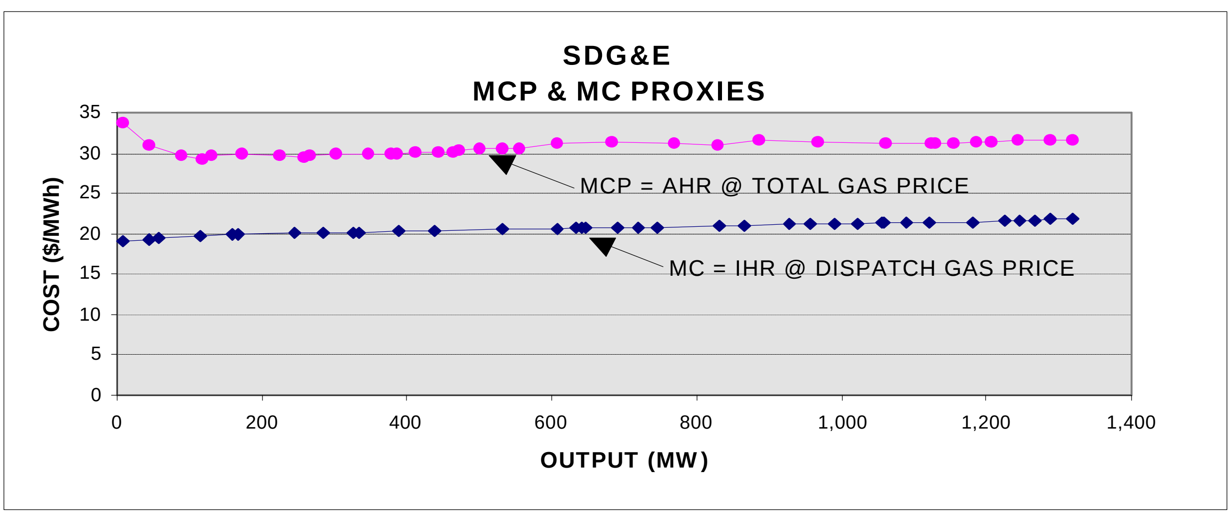

Figure C-7-SDG&E

TABLE C-8: ALL IOUs SYSTEM AVERAGE COST CALCULATIONS

SUMMARY IHR DATA

PLANT	BLK #	INC MW	CUM MW	IHR Btu/kWh	Unit Cost Disp. $/MWh	Unit Cost Total $/MWh	Unit Cost * MW Dispatch Unit	Unit Cost * MW Dispatch Cumul.	Unit Cost * MW Total Unit	Unit Cost * MW Total Cumul.	Cumul. IHR Disp. $/MWh	Cumul. IHR Total $/MWh
cw34	2	40	40	7,013	11.7	14.8	468	468	592	592	11.7	14.8
cw34	3	60	100	7,064	11.8	14.9	708	1176	894	1486	11.8	14.9
cw34	4	140	240	7,334	12.2	15.5	1715	2891	2167	3653	12.0	15.2
cw34	5	132	372	8,018	13.4	16.9	1768	4659	2233	5886	12.5	15.8
mos7	2	135	507	7,196	14.6	18.0	1972	6631	2429	8315	13.1	16.4
mos6	2	135	642	7,370	15.0	18.4	2020	8650	2487	10802	13.5	16.8
cw01	2	13	655	9,320	15.6	19.7	202	8853	256	11058	13.5	16.9
cw02	2	16	671	9,368	15.6	19.8	250	9103	316	11374	13.6	17.0
cw02	3	16	687	9,540	15.9	20.1	255	9358	322	11696	13.6	17.0
cw01	3	13	700	9,549	15.9	20.1	207	9565	262	11958	13.7	17.1
mos7	3	185	885	7,890	16.0	19.7	2963	12528	3649	15607	14.2	17.6
cw02	4	16	901	9,742	16.3	20.6	260	12789	329	15936	14.2	17.7
cw01	4	13	914	9,808	16.4	20.7	213	13001	269	16205	14.2	17.7
mos6	3	185	1099	8,146	16.5	20.4	3059	16061	3767	19972	14.6	18.2
cw02	5	14	1113	9,960	16.6	21.0	233	16293	294	20266	14.6	18.2
cw01	5	9	1122	10,050	16.8	21.2	151	16444	191	20457	14.7	18.2
pit7	3	180	1302	8,476	17.2	21.2	3097	19542	3814	24272	15.0	18.6
mos7	4	221	1523	8,485	17.2	21.2	3806	23348	4688	28959	15.3	19.0
con7	2	39	1562	8,496	17.2	21.2	673	24021	828	29788	15.4	19.1
con7	3	85	1647	8,503	17.3	21.3	1467	25488	1807	31595	15.5	19.2
pit7	2	60	1707	8,555	17.4	21.4	1042	26530	1283	32878	15.5	19.3
con6	3	85	1792	8,555	17.4	21.4	1476	28006	1818	34696	15.6	19.4
mos6	4	221	2013	8,668	17.6	21.7	3889	31895	4789	39485	15.8	19.6
mor4	2	39	2052	8,703	17.7	21.8	689	32584	849	40334	15.9	19.7
mos6	5	148	2200	8,714	17.7	21.8	2618	35202	3224	43558	16.0	19.8
pit5	2	35	2235	8,744	17.8	21.9	621	35824	765	44323	16.0	19.8
con6	2	39	2274	8,756	17.8	21.9	693	36517	854	45177	16.1	19.9
mos7	5	148	2422	8,760	17.8	21.9	2632	39149	3241	48418	16.2	20.0
pit7	4	216	2638	8,762	17.8	21.9	3842	42991	4732	53150	16.3	20.1
pit6	2	35	2673	8,821	17.9	22.1	627	43617	772	53921	16.3	20.2
mor4	3	84	2757	8,848	18.0	22.1	1509	45126	1858	55780	16.4	20.2
pit6	3	82	2839	8,868	18.0	22.2	1476	46602	1818	57597	16.4	20.3
hnp4	2	20	2859	8,873	18.0	22.2	360	46963	444	58041	16.4	20.3
con6	4	102	2961	8,877	18.0	22.2	1838	48801	2264	60305	16.5	20.4
pit5	3	82	3043	8,900	18.1	22.3	1482	50282	1825	62129	16.5	20.4
pot3	3	52	3095	8,924	18.1	22.3	942	51224	1160	63289	16.6	20.4
con7	4	102	3197	8,933	18.1	22.3	1850	53074	2278	65567	16.6	20.5
pit3&4	3	82	3279	8,983	18.2	22.5	1495	54569	1842	67409	16.6	20.6
pit1&2	3	82	3361	9,003	18.3	22.5	1499	56068	1846	69254	16.7	20.6
hnp4	3	82	3443	9,044	18.4	22.6	1506	57573	1854	71109	16.7	20.7
mor3	2	39	3482	9,056	18.4	22.6	717	58290	883	71992	16.7	20.7
mor3	3	84	3566	9,064	18.4	22.7	1546	59836	1903	73895	16.8	20.7
pot3	2	5	3571	9,066	18.4	22.7	92	59928	113	74008	16.8	20.7
pit1&2	2	20	3591	9,079	18.4	22.7	369	60296	454	74462	16.8	20.7
mor4	4	101	3692	9,083	18.4	22.7	1862	62159	2293	76756	16.8	20.8
mor3	4	101	3793	9,100	18.5	22.8	1866	64025	2298	79053	16.9	20.8
pit6	4	97	3890	9,135	18.5	22.8	1799	65823	2215	81269	16.9	20.9
pit5	4	97	3987	9,135	18.5	22.8	1799	67622	2215	83484	17.0	20.9
mor3	5	68	4055	9,159	18.6	22.9	1264	68887	1557	85041	17.0	21.0
pot3	4	62	4117	9,276	18.8	23.2	1167	70054	1438	86479	17.0	21.0
pit3&4	2	20	4137	9,276	18.8	23.2	377	70431	464	86943	17.0	21.0
mor4	5	68	4205	9,314	18.9	23.3	1286	71716	1583	88526	17.1	21.1
pit5	5	65	4270	9,344	19.0	23.4	1233	72949	1518	90044	17.1	21.1
sba1	2	7	4277	8,560	19.0	24.5	133	73082	171	90216	17.1	21.1
hnp4	4	96	4373	9,379	19.0	23.4	1828	74910	2251	92467	17.1	21.1
pit1&2	4	96	4469	9,391	19.1	23.5	1830	76740	2254	94721	17.2	21.2
mor1&2	2	20	4489	9,407	19.1	23.5	382	77122	470	95191	17.2	21.2
mor1&2	3	82	4571	9,441	19.2	23.6	1572	78694	1936	97127	17.2	21.2
pit7	5	144	4715	9,469	19.2	23.7	2768	81462	3409	100536	17.3	21.3
pit3&4	4	96	4811	9,529	19.3	23.8	1857	83319	2287	102822	17.3	21.4
pit6	5	65	4876	9,579	19.4	23.9	1264	84583	1557	104379	17.3	21.4
sba1	3	37	4913	8,764	19.5	25.1	720	85303	927	105306	17.4	21.4
mor1&2	4	96	5009	9,675	19.6	24.2	1885	87188	2322	107628	17.4	21.5
hnp4	5	66	5075	9,724	19.7	24.3	1303	88491	1604	109233	17.4	21.5
con7	5	68	5143	9,754	19.8	24.4	1346	89837	1658	110891	17.5	21.6
sba3	2	13	5156	8,937	19.8	25.6	258	90095	332	111223	17.5	21.6
con6	5	68	5224	9,811	19.9	24.5	1354	91450	1668	112891	17.5	21.6
enc5	2	59	5283	9,016	20.0	25.8	1181	92630	1521	114412	17.5	21.7

SUMMARY AHR DATA

PLANT	BLK #	INC MW	CUM MW	AHR Btu/kWh	Unit Cost Disp. $/MWh	Unit Cost Total $/MWh	Unit Cost * MW Dispatch Unit	Unit Cost * MW Dispatch Cumul.	Unit Cost * MW Total Unit	Unit Cost * MW Total Cumul.	Cumul. IHR Disp. $/MWh	Cumul. IHR Total $/MWh
cw01	2	13	13	11,259	18.8	23.8	244	244	309	309	18.8	23.8
cw01	3	13	26	10,587	17.7	22.3	230	474	290	599	18.2	23.0
cw01	4	13	39	10,343	17.3	21.8	225	699	284	883	17.9	22.6
cw01	5	9	48	10,264	17.1	21.7	154	853	195	1078	17.8	22.5
cw02	2	16	64	11,401	19.0	24.1	305	1158	385	1463	18.1	22.9
cw02	3	16	80	10,650	17.8	22.5	285	1442	360	1822	18.0	22.8
cw02	4	16	96	10,370	17.3	21.9	277	1719	350	2172	17.9	22.6
cw02	5	14	110	10,262	17.1	21.7	240	1959	303	2476	17.8	22.5
orb1	2	120	230	10,354	26.7	26.7	3206	5165	3206	5681	22.5	24.7
orb1	3	130	360	9,753	25.2	25.2	3271	8436	3271	8952	23.4	24.9
orb1	4	120	480	9,486	24.5	24.5	2937	11373	2937	11889	23.7	24.8
orb1	5	130	610	9,382	24.2	24.2	3147	14520	3147	15036	23.8	24.6
pot3	2	5	615	10,853	22.0	27.1	110	14630	136	15171	23.8	24.7
pot3	3	52	667	10,207	20.7	25.5	1077	15707	1327	16498	23.5	24.7
pot3	4	62	729	9,689	19.7	24.2	1219	16927	1502	18000	23.2	24.7
pot3	5	41	770	9,686	19.7	24.2	806	17733	993	18993	23.0	24.7
ala5&6	2	160	930	10,532	27.2	27.2	4348	22080	4348	23341	23.7	25.1
ala5&6	3	180	1110	9,810	25.3	25.3	4556	26636	4556	27896	24.0	25.1
ala5&6	4	180	1290	9,560	24.7	24.7	4440	31076	4440	32336	24.1	25.1
ala5&6	5	180	1470	9,491	24.5	24.5	4407	35483	4407	36743	24.1	25.0
red7&8	2	100	1570	10,808	27.9	27.9	2789	38272	2789	39532	24.4	25.2
red7&8	3	300	1870	9,995	25.8	25.8	7736	46008	7736	47268	24.6	25.3
red7&8	4	140	2010	9,633	24.9	24.9	3479	49487	3479	50747	24.6	25.2
red7&8	5	160	2170	9,548	24.6	24.6	3941	53429	3941	54689	24.6	25.2
cw34	2	40	2210	13,307	22.2	28.1	889	54318	1123	55812	24.6	25.3
cw34	3	60	2270	11,822	19.7	24.9	1185	55502	1497	57309	24.5	25.2
cw34	4	140	2410	10,361	17.3	21.9	2422	57924	3061	60369	24.0	25.0
cw34	5	132	2542	9,506	15.9	20.1	2095	60020	2648	63017	23.6	24.8
hnp4	2	20	2562	11,642	23.6	29.1	473	60493	582	63599	23.6	24.8
hnp4	3	82	2644	10,585	21.5	26.5	1762	62254	2170	65769	23.5	24.9
hnp4	4	96	2740	9,985	20.3	25.0	1946	64200	2396	68165	23.4	24.9
hnp4	5	66	2806	9,854	20.0	24.6	1320	65521	1626	69791	23.4	24.9
mor4	2	39	2845	11,694	23.7	29.2	926	66446	1140	70931	23.4	24.9
mor4	3	84	2929	10,292	20.9	25.7	1755	68201	2161	73092	23.3	25.0
mor4	4	101	3030	9,714	19.7	24.3	1992	70193	2453	75545	23.2	24.9
mor4	5	68	3098	9,561	19.4	23.9	1320	71513	1625	77171	23.1	24.9
hun3	2	30	3128	11,342	29.3	29.3	878	72391	878	78048	23.1	25.0
hun3	3	30	3158	10,862	28.0	28.0	841	73231	841	78889	23.2	25.0
hun3	4	30	3188	10,602	27.4	27.4	821	74052	821	79710	23.2	25.0
hun3	5	35	3223	10,474	27.0	27.0	946	74998	946	80656	23.3	25.0
pit6	2	35	3258	11,709	23.8	29.3	832	75830	1025	81680	23.3	25.1
pit6	3	82	3340	10,352	21.0	25.9	1723	77553	2122	83802	23.2	25.1
pit6	4	97	3437	9,751	19.8	24.4	1920	79473	2365	86167	23.1	25.1
pit6	5	65	3502	9,625	19.5	24.1	1270	80743	1564	87731	23.1	25.1
hun4	2	30	3532	11,407	29.4	29.4	883	81626	883	88614	23.1	25.1
hun4	3	30	3562	10,926	28.2	28.2	846	82472	846	89460	23.2	25.1
hun4	4	30	3592	10,661	27.5	27.5	825	83297	825	90285	23.2	25.1
hun4	5	45	3637	10,474	27.0	27.0	1216	84513	1216	91501	23.2	25.2
con6	2	39	3676	11,860	24.1	29.6	939	85452	1156	92657	23.2	25.2
con6	3	85	3761	10,300	20.9	25.7	1777	87229	2189	94846	23.2	25.2
con6	4	102	3863	9,579	19.4	23.9	1983	89212	2443	97288	23.1	25.2
con6	5	68	3931	9,479	19.2	23.7	1309	90521	1611	98900	23.0	25.2
mor3	2	39	3970	12,056	24.5	30.1	954	91475	1175	100075	23.0	25.2
mor3	3	84	4054	10,616	21.6	26.5	1810	93286	2229	102305	23.0	25.2
mor3	4	101	4155	9,950	20.2	24.9	2040	95326	2512	104817	22.9	25.2
mor3	5	68	4223	9,712	19.7	24.3	1341	96666	1651	106468	22.9	25.2
con7	2	39	4262	12,112	24.6	30.3	959	97625	1181	107649	22.9	25.3
con7	3	85	4347	10,361	21.0	25.9	1788	99413	2202	109851	22.9	25.3
con7	4	102	4449	9,622	19.5	24.1	1992	101406	2454	112305	22.8	25.2
con7	5	68	4517	9,517	19.3	23.8	1314	102719	1618	113923	22.7	25.2
pit5	2	35	4552	12,186	24.7	30.5	866	103585	1066	114989	22.8	25.3
pit5	3	82	4634	10,598	21.5	26.5	1764	105349	2173	117161	22.7	25.3
pit5	4	97	4731	9,907	20.1	24.8	1951	107300	2402	119564	22.7	25.3
pit5	5	65	4796	9,712	19.7	24.3	1281	108581	1578	121142	22.6	25.3
mor1&2	2	20	4816	12,246	24.9	30.6	497	109079	612	121754	22.6	25.3
mor1&2	3	82	4898	11,128	22.6	27.8	1852	110931	2281	124035	22.6	25.3
mor1&2	4	96	4994	10,438	21.2	26.1	2034	112965	2505	126541	22.6	25.3
mor1&2	5	66	5060	10,266	20.8	25.7	1375	114341	1694	128235	22.6	25.3

- Continued on Next Page -

TABLE C-8: ALL IOUs SYSTEM AVERAGE COST CALCULATIONS - CONTINUED

SUMMARY IHR DATA

PLANT	BLK #	INC MW	CUM MW	*IHR* Btu/kWh	*Unit Cost* Disp. $/MWh	*Unit Cost* Total $/MWh	*Unit Cost * MW* Dispatch Unit	*Unit Cost * MW* Dispatch Cumul.	*Unit Cost * MW* Total Unit	*Unit Cost * MW* Total Cumul.	*Cumul. IHR* Disp. $/MWh	*Cumul. IHR* Total $/MWh
hnp3	2	17	5300	9,876	20.0	24.7	341	92971	420	114832	17.5	21.7
sba3	3	43	5343	9,082	20.2	26.0	867	93838	1117	115949	17.6	21.7
sba2	2	8	5351	9,127	20.3	26.1	162	94000	209	116158	17.6	21.7
hig3&4	2	14	5365	7,899	20.4	20.4	285	94286	285	116443	17.6	21.7
enc5	3	79	5444	9,190	20.4	26.3	1612	95897	2076	118519	17.6	21.8
mor1&2	5	66	5510	10,081	20.5	25.2	1351	97248	1663	120183	17.6	21.8
sba2	3	37	5547	9,287	20.6	26.6	763	98011	983	121166	17.7	21.8
sba1	4	44	5591	9,368	20.8	26.8	915	98926	1179	122344	17.7	21.9
enc3	2	8	5599	9,374	20.8	26.8	166	99092	214	122559	17.7	21.9
hig3&4	3	26	5625	8,096	20.9	20.9	543	99635	543	123102	17.7	21.9
pit1&2	5	66	5691	10,331	21.0	25.8	1384	101019	1705	124807	17.8	21.9
pot3	5	41	5732	10,341	21.0	25.9	861	101880	1060	125866	17.8	22.0
enc4	2	53	5785	9,472	21.0	27.1	1114	102995	1436	127302	17.8	22.0
hnp2	2	17	5802	10,364	21.0	25.9	358	103352	440	127743	17.8	22.0
ala5&6	2	160	5962	8,155	21.0	21.0	3366	106719	3366	131109	17.9	22.0
hmb1&2	3	27	5989	10,366	21.0	25.9	568	107287	700	131809	17.9	22.0
sba3	4	51	6040	9,487	21.1	27.1	1074	108361	1384	133193	17.9	22.1
orb1	2	120	6160	8,171	21.1	21.1	2530	110891	2530	135722	18.0	22.0
orb2	2	175	6335	8,192	21.1	21.1	3699	114589	3699	139421	18.1	22.0
enc5	4	94	6429	9,605	21.3	27.5	2004	116594	2582	142003	18.1	22.1
enc4	3	74	6503	9,617	21.3	27.5	1580	118174	2035	144039	18.2	22.1
enc3	3	27	6530	9,635	21.4	27.6	578	118751	744	144783	18.2	22.2
hmb1&2	2	16	6546	10,543	21.4	26.4	342	119094	422	145204	18.2	22.2
hig3&4	4	30	6576	8,338	21.5	21.5	645	119739	645	145850	18.2	22.2
enc1	2	7	6583	9,736	21.6	27.8	151	119890	195	146045	18.2	22.2
enc2	2	6	6589	9,763	21.7	27.9	130	120020	168	146212	18.2	22.2
sba2	4	45	6634	9,763	21.7	27.9	975	120996	1256	147469	18.2	22.2
hig1&2	2	10	6644	8,413	21.7	21.7	217	121213	217	147686	18.2	22.2
orb1	3	130	6774	8,429	21.7	21.7	2827	124040	2827	150513	18.3	22.2
eti3&4	2	120	6894	8,438	21.8	21.8	2612	126652	2612	153125	18.4	22.2
hig1&2	3	20	6914	8,438	21.8	21.8	435	127087	435	153560	18.4	22.2
man1&2	2	100	7014	8,443	21.8	21.8	2178	129266	2178	155739	18.4	22.2
ala3&4	2	120	7134	8,443	21.8	21.8	2614	131880	2614	158353	18.5	22.2
enc1	3	27	7161	9,815	21.8	28.1	588	132468	758	159110	18.5	22.2
orb2	3	175	7336	8,459	21.8	21.8	3819	136287	3819	162930	18.6	22.2
hig1&2	4	18	7354	8,471	21.9	21.9	393	136681	393	163323	18.6	22.2
hig3&4	5	9	7363	8,485	21.9	21.9	197	136878	197	163520	18.6	22.2
hig1&2	5	10	7373	8,495	21.9	21.9	219	137097	219	163739	18.6	22.2
enc2	3	26	7399	9,889	22.0	28.3	571	137668	735	164475	18.6	22.2
hnp3	3	27	7426	10,861	22.0	27.2	595	138263	733	165208	18.6	22.2
hun1&2	2	100	7526	8,552	22.1	22.1	2207	140469	2207	167414	18.7	22.2
red7&8	2	100	7626	8,557	22.1	22.1	2208	142677	2208	169622	18.7	22.2
enc4	4	87	7713	9,966	22.1	28.5	1925	144602	2480	172102	18.7	22.3
sba3	5	34	7747	10,027	22.3	28.7	757	145359	975	173077	18.8	22.3
ala3&4	3	160	7907	8,639	22.3	22.3	3566	148925	3566	176643	18.8	22.3
hnp2	3	27	7934	10,981	22.3	27.5	602	149527	741	177384	18.8	22.4
eti3&4	3	160	8094	8,641	22.3	22.3	3567	153094	3567	180951	18.9	22.4
ala5&6	3	180	8274	8,656	22.3	22.3	4020	157113	4020	184971	19.0	22.4
sbr1&2	2	28	8302	8,681	22.4	22.4	627	157741	627	185598	19.0	22.4
els1-4	2	190	8492	8,715	22.5	22.5	4272	162013	4272	189870	19.1	22.4
orb1	4	120	8612	8,742	22.6	22.6	2706	164719	2706	192576	19.1	22.4
enc5	5	63	8675	10,163	22.6	29.1	1421	166140	1831	194408	19.2	22.4
sba1	5	29	8704	10,169	22.6	29.1	655	166795	843	195251	19.2	22.4
red7&8	3	300	9004	8,759	22.6	22.6	6779	173575	6779	202030	19.3	22.4
hun1&2	3	100	9104	8,768	22.6	22.6	2262	175837	2262	204293	19.3	22.4
man1&2	3	105	9209	8,799	22.7	22.7	2384	178221	2384	206676	19.4	22.4
enc1	4	32	9241	10,231	22.7	29.3	727	178947	936	207613	19.4	22.5
orb2	4	175	9416	8,818	22.7	22.7	3981	182929	3981	211594	19.4	22.5
pit3&4	5	66	9482	11,211	22.8	28.0	1502	184431	1850	213444	19.5	22.5
enc2	4	31	9513	10,258	22.8	29.3	706	185137	910	214353	19.5	22.5
sba4	3	36	9549	10,268	22.8	29.4	821	185957	1057	215411	19.5	22.6
sba4	2	1	9550	10,278	22.8	29.4	23	185980	29	215440	19.5	22.6
enc3	4	33	9583	10,375	23.0	29.7	760	186740	979	216419	19.5	22.6
ala3&4	4	160	9743	8,933	23.0	23.0	3688	190428	3688	220107	19.5	22.6
eti3&4	4	160	9903	8,943	23.1	23.1	3692	194120	3692	223799	19.6	22.6
sba2	5	30	9933	10,407	23.1	29.8	693	194813	893	224691	19.6	22.6
els1-4	3	250	10183	8,963	23.1	23.1	5781	200594	5781	230473	19.7	22.6
hmb1&2	4	31	10214	11,392	23.1	28.5	717	201311	883	231355	19.7	22.7

SUMMARY AHR DATA

PLANT	BLK #	INC MW	CUM MW	*AHR* Btu/kWh	*Unit Cost* Disp. $/MWh	*Unit Cost* Total $/MWh	*Unit Cost * MW* Dispatch Unit	*Unit Cost * MW* Dispatch Cumul.	*Unit Cost * MW* Total Unit	*Unit Cost * MW* Total Cumul.	*Cumul. IHR* Disp. $/MWh	*Cumul. IHR* Total $/MWh
man1&2	2	100	5160	12,114	31.3	31.3	3125	117466	3125	131360	22.8	25.5
man1&2	3	105	5265	10,087	26.0	26.0	2732	120198	2732	134092	22.8	25.5
man1&2	4	95	5360	9,706	25.0	25.0	2379	122577	2379	136471	22.9	25.5
pit3&4	2	20	5380	12,905	26.2	32.3	524	123101	645	137116	22.9	25.5
pit3&4	3	82	5462	11,388	23.1	28.5	1896	124997	2335	139451	22.9	25.5
pit3&4	4	96	5558	10,408	21.1	26.0	2028	127025	2498	141949	22.9	25.5
pit3&4	5	66	5624	10,341	21.0	25.9	1385	128411	1706	143655	22.8	25.5
hun1&2	2	100	5724	12,570	32.4	32.4	3243	131654	3243	146898	23.0	25.7
hun1&2	3	100	5824	10,331	26.7	26.7	2665	134319	2665	149564	23.1	25.7
hun1&2	4	100	5924	9,822	25.3	25.3	2534	136853	2534	152098	23.1	25.7
hun1&2	5	90	6014	9,666	24.9	24.9	2244	139098	2244	154342	23.1	25.7
pit7	2	60	6074	13,001	26.4	32.5	1584	140681	1950	156292	23.2	25.7
pit7	3	180	6254	11,062	22.5	27.7	4042	144723	4978	161270	23.1	25.8
pit7	4	216	6470	9,977	20.3	24.9	4375	149098	5387	166658	23.0	25.8
pit7	5	144	6614	9,705	19.7	24.3	2837	151935	3494	170152	23.0	25.7
mos7	2	135	6749	13,304	27.0	33.3	3646	155581	4490	174642	23.1	25.9
mos7	3	185	6934	9,758	19.8	24.4	3665	159246	4513	179155	23.0	25.8
mos7	4	221	7155	9,079	18.4	22.7	4073	163319	5016	184171	22.8	25.7
mos7	5	148	7303	8,949	18.2	22.4	2689	166007	3311	187482	22.7	25.7
mos6	2	135	7438	13,370	27.1	33.4	3664	169671	4512	191994	22.8	25.8
mos6	3	185	7623	9,918	20.1	24.8	3725	173396	4587	196581	22.7	25.8
mos6	4	221	7844	9,273	18.8	23.2	4160	177556	5123	201705	22.6	25.7
mos6	5	148	7992	9,115	18.5	22.8	2739	180295	3373	205077	22.6	25.7
pit1&2	2	20	8012	13,412	27.2	33.5	545	180839	671	205748	22.6	25.7
pit1&2	3	82	8094	11,673	23.7	29.2	1943	182782	2393	208141	22.6	25.7
pit1&2	4	96	8190	10,573	21.5	26.4	2060	184843	2537	210678	22.6	25.7
pit1&2	5	66	8256	10,339	21.0	25.8	1385	186228	1706	212384	22.6	25.7
sba1	2	7	8263	11,778	26.1	33.7	183	186411	236	212620	22.6	25.7
sba1	3	37	8300	10,613	23.6	30.4	872	187283	1123	213743	22.6	25.8
sba1	4	44	8344	9,922	22.0	28.4	969	188252	1249	214992	22.6	25.8
sba1	5	29	8373	9,857	21.9	28.2	635	188886	818	215809	22.6	25.8
sba3	2	13	8386	11,880	26.4	34.0	343	189229	442	216251	22.6	25.8
sba3	3	43	8429	10,680	23.7	30.5	1020	190249	1313	217564	22.6	25.8
sba3	4	51	8480	10,062	22.3	28.8	1139	191388	1468	219032	22.6	25.8
sba3	5	34	8514	9,961	22.1	28.5	752	192140	969	220000	22.6	25.8
orb2	2	175	8689	13,188	34.0	34.0	5954	198094	5954	225955	22.8	26.0
orb2	3	175	8864	10,168	26.2	26.2	4591	202685	4591	230545	22.9	26.0
orb2	4	175	9039	9,595	24.8	24.8	4332	207017	4332	234877	22.9	26.0
orb2	5	175	9214	9,442	24.4	24.4	4263	211280	4263	239141	22.9	26.0
sba2	2	8	9222	12,099	26.9	34.6	215	211495	277	239417	22.9	26.0
sba2	3	37	9259	11,007	24.4	31.5	904	212399	1165	240582	22.9	26.0
sba2	4	45	9304	10,352	23.0	29.6	1034	213433	1332	241914	22.9	26.0
sba2	5	30	9334	10,259	22.8	29.3	683	214116	880	242795	22.9	26.0
enc1	2	7	9341	12,632	28.0	36.1	196	214313	253	243048	22.9	26.0
enc1	3	27	9368	11,483	25.5	32.8	688	215001	887	243934	23.0	26.0
enc1	4	32	9400	10,831	24.0	31.0	769	215770	991	244926	23.0	26.1
enc1	5	21	9421	10,737	23.8	30.7	501	216271	645	245570	23.0	26.1
enc3	2	8	9429	13,155	29.2	37.6	234	216504	301	245871	23.0	26.1
enc3	3	27	9456	11,675	25.9	33.4	700	217204	902	246773	23.0	26.1
enc3	4	33	9489	10,933	24.3	31.3	801	218005	1032	247805	23.0	26.1
enc3	5	22	9511	10,891	24.2	31.1	532	218537	685	248490	23.0	26.1
enc4	2	53	9564	13,472	29.9	38.5	1585	220122	2042	250532	23.0	26.2
enc4	3	74	9638	11,055	24.5	31.6	1816	221938	2340	252872	23.0	26.2
enc4	4	87	9725	10,494	23.3	30.0	2027	223965	2611	255483	23.0	26.3
enc4	5	59	9784	10,398	23.1	29.7	1362	225327	1755	257237	23.0	26.3
enc5	2	59	9843	13,485	29.9	38.6	1766	227093	2275	259513	23.1	26.4
enc5	3	79	9922	10,741	23.8	30.7	1884	228977	2427	261940	23.1	26.4
enc5	4	94	10016	10,144	22.5	29.0	2117	231094	2727	264667	23.1	26.4
enc5	5	63	10079	10,055	22.3	28.8	1406	232500	1812	266478	23.1	26.4
eti3&4	2	120	10199	15,141	39.1	39.1	4688	237188	4688	271166	23.3	26.6
eti3&4	3	160	10359	11,005	28.4	28.4	4543	241730	4543	275709	23.3	26.6
eti3&4	4	160	10519	10,078	26.0	26.0	4160	245891	4160	279869	23.4	26.6
eti3&4	5	160	10679	9,798	25.3	25.3	4045	249935	4045	283914	23.4	26.6
enc2	2	6	10685	14,131	31.4	40.4	188	250124	242	284156	23.4	26.6
enc2	3	26	10711	12,451	27.6	35.6	719	250842	926	285082	23.4	26.6
enc2	4	31	10742	11,406	25.3	32.6	785	251627	1011	286093	23.4	26.6
enc2	5	21	10763	11,135	24.7	31.8	519	252146	669	286762	23.4	26.6
hnp3	2	17	10780	16,339	33.2	40.8	564	252710	694	287456	23.4	26.7

- Continued on Next Page -

TABLE C-8: ALL IOUs SYSTEM AVERAGE COST CALCULATIONS - CONTINUED

				SUMMARY IHR DATA														SUMMARY AHR DATA							
					Unit Cost		Unit Cost * MW				Cumul. IHR							Unit Cost		Unit Cost * MW				Cumul. IHR	
	BLK	INC	CUM	IHR	Disp.	Total	Dispatch		Total		Disp.	Total		BLK	INC	CUM	AHR	Disp.	Total	Dispatch		Total		Disp.	Total
PLANT	#	MW	MW	Btu/kWh	$/MWh	$/MWh	Unit	Cumul.	Unit	Cumul.	$/MWh	$/MWh	PLANT	#	MW	MW	Btu/kWh	$/MWh	$/MWh	Unit	Cumul.	Unit	Cumul.	$/MWh	$/MWh
enc4	5	59	10273	10,437	23.2	29.8	1367	202678	1761	233117	19.7	22.7	hnp3	3	27	10807	12,974	26.3	32.4	711	253421	876	288332	23.4	26.7
red5&6	2	70	10343	8,992	23.2	23.2	1624	204302	1624	234741	19.8	22.7	hnp3	4	32	10839	12,336	25.0	30.8	801	254223	987	289319	23.5	26.7
red7&8	4	140	10483	9,028	23.3	23.3	3261	207563	3261	238002	19.8	22.7	hnp3	5	21	10860	12,471	25.3	31.2	532	254754	655	289974	23.5	26.7
hun1&2	4	100	10583	9,050	23.4	23.4	2335	209898	2335	240337	19.8	22.7	els1-4	2	190	11050	16,141	41.6	41.6	7913	262667	7913	297886	23.8	27.0
sbr1&2	3	28	10611	9,056	23.4	23.4	654	210552	654	240991	19.8	22.7	els1-4	3	250	11300	11,525	29.7	29.7	7433	270100	7433	305320	23.9	27.0
ala5&6	4	180	10791	9,074	23.4	23.4	4214	214766	4214	245205	19.9	22.7	els1-4	4	250	11550	10,517	27.1	27.1	6783	276884	6783	312103	24.0	27.0
orb1	5	130	10921	9,112	23.5	23.5	3056	217822	3056	248261	19.9	22.7	els1-4	5	270	11820	10,188	26.3	26.3	7097	283980	7097	319200	24.0	27.0
hun3	2	30	10951	9,126	23.5	23.5	706	218528	706	248967	20.0	22.7	ala3&4	2	120	11940	16,210	41.8	41.8	5019	288999	5019	324218	24.2	27.2
ala1&2	2	70	11021	9,127	23.5	23.5	1648	220177	1648	250615	20.0	22.7	ala3&4	3	160	12100	11,407	29.4	29.4	4709	293708	4709	328927	24.3	27.2
red5&6	3	90	11111	9,134	23.6	23.6	2121	222297	2121	252736	20.0	22.7	ala3&4	4	160	12260	10,311	26.6	26.6	4256	297964	4256	333184	24.3	27.2
hun4	2	30	11141	9,137	23.6	23.6	707	223005	707	253444	20.0	22.7	ala3&4	5	160	12420	9,960	25.7	25.7	4111	302076	4111	337295	24.3	27.2
sba4	4	45	11186	10,741	23.8	30.7	1073	224078	1382	254826	20.0	22.8	sba4	2	1	12421	14,726	32.7	42.1	33	302108	42	337337	24.3	27.2
red7&8	5	160	11346	9,248	23.9	23.9	3818	227895	3818	258643	20.1	22.8	sba4	3	36	12457	13,382	29.7	38.3	1069	303178	1378	338715	24.3	27.2
enc2	5	21	11367	10,760	23.9	30.8	502	228397	646	259290	20.1	22.8	sba4	4	45	12502	12,128	26.9	34.7	1212	304389	1561	340276	24.3	27.2
els1-4	4	250	11617	9,259	23.9	23.9	5972	234369	5972	265262	20.2	22.8	sba4	5	30	12532	11,847	26.3	33.9	789	305178	1016	341292	24.4	27.2
eti1&2	2	60	11677	9,264	23.9	23.9	1434	235803	1434	266696	20.2	22.8	hmb1&2	2	16	12548	16,853	34.2	42.1	547	305726	674	341966	24.4	27.3
orb2	5	175	11852	9,268	23.9	23.9	4185	239988	4185	270880	20.2	22.9	hmb1&2	3	27	12575	13,245	26.9	33.1	726	306452	894	342861	24.4	27.3
man1&2	4	95	11947	9,279	23.9	23.9	2274	242262	2274	273155	20.3	22.9	hmb1&2	4	31	12606	12,142	24.6	30.4	764	307216	941	343802	24.4	27.3
ala3&4	5	160	12107	9,305	24.0	24.0	3841	246103	3841	276996	20.3	22.9	hmb1&2	5	21	12627	12,167	24.7	30.4	519	307734	639	344440	24.4	27.3
hun3	3	30	12137	9,309	24.0	24.0	721	246823	721	277716	20.3	22.9	hnp2	2	17	12644	16,865	34.2	42.2	582	308316	717	345157	24.4	27.3
eti3&4	5	160	12297	9,322	24.0	24.0	3848	250671	3848	281564	20.4	22.9	hnp2	3	27	12671	13,382	27.2	33.5	733	309050	903	346060	24.4	27.3
red5&6	4	90	12387	9,324	24.1	24.1	2165	252837	2165	283729	20.4	22.9	hnp2	4	32	12703	12,517	25.4	31.3	813	309863	1001	347062	24.4	27.3
hnp2	4	32	12419	11,861	24.1	29.7	771	253607	949	284678	20.4	22.9	hnp2	5	21	12724	12,433	25.2	31.1	530	310393	653	347714	24.4	27.3
ala1&2	3	90	12509	9,341	24.1	24.1	2169	255776	2169	286847	20.4	22.9	eti1&2	2	60	12784	16,432	42.4	42.4	2544	312937	2544	350258	24.5	27.4
ala5&6	5	180	12689	9,375	24.2	24.2	4354	260130	4354	291201	20.5	22.9	eti1&2	3	60	12844	12,244	31.6	31.6	1895	314832	1895	352153	24.5	27.4
hun1&2	5	90	12779	9,379	24.2	24.2	2178	262308	2178	293379	20.5	23.0	eti1&2	4	60	12904	11,371	29.3	29.3	1760	316592	1760	353914	24.5	27.4
sbr1&2	4	28	12807	9,384	24.2	24.2	678	262986	678	294057	20.5	23.0	eti1&2	5	64	12968	11,106	28.7	28.7	1834	318426	1834	355747	24.6	27.4
enc1	5	21	12828	10,909	24.2	31.2	509	263494	655	294712	20.5	23.0	ala1&2	2	70	13038	17,605	45.4	45.4	3179	321605	3179	358927	24.7	27.5
hun4	3	30	12858	9,387	24.2	24.2	727	264221	727	295438	20.5	23.0	ala1&2	3	90	13128	12,222	31.5	31.5	2838	324443	2838	361765	24.7	27.6
red5&6	5	80	12938	9,535	24.6	24.6	1968	266189	1968	297407	20.6	23.0	ala1&2	4	90	13218	11,084	28.6	28.6	2574	327017	2574	364339	24.7	27.6
hun4	4	30	12968	9,568	24.7	24.7	741	266929	741	298147	20.6	23.0	ala1&2	5	80	13298	10,734	27.7	27.7	2216	329233	2216	366554	24.8	27.6
els1-4	5	270	13238	9,583	24.7	24.7	6675	273605	6675	304822	20.7	23.0	red5&6	2	70	13368	18,702	48.3	48.3	3378	332610	3378	369932	24.9	27.7
hun3	4	30	13268	9,606	24.8	24.8	743	274348	743	305566	20.7	23.0	red5&6	3	90	13458	12,511	32.3	32.3	2905	335515	2905	372837	24.9	27.7
eti1&2	3	60	13328	9,627	24.8	24.8	1490	275838	1490	307056	20.7	23.0	red5&6	4	90	13548	11,144	28.8	28.8	2588	338103	2588	375424	25.0	27.7
hnp3	4	32	13360	12,246	24.9	30.6	796	276634	980	308036	20.7	23.1	red5&6	5	80	13628	10,661	27.5	27.5	2200	340303	2200	377625	25.0	27.7
ala1&2	4	90	13450	9,663	24.9	24.9	2244	278878	2244	310280	20.7	23.1	sbr1&2	2	28	13656	18,968	48.9	48.9	1370	341674	1370	378995	25.0	27.8
sbr1&2	5	28	13478	9,667	24.9	24.9	698	279576	698	310978	20.7	23.1	sbr1&2	3	28	13684	13,553	35.0	35.0	979	342653	979	379974	25.0	27.8
hun4	5	45	13523	9,695	25.0	25.0	1126	280701	1126	312103	20.8	23.1	sbr1&2	4	28	13712	12,072	31.1	31.1	872	343525	872	380846	25.1	27.8
enc3	5	22	13545	11,377	25.3	32.5	556	281257	716	312819	20.8	23.1	sbr1&2	5	28	13740	11,426	29.5	29.5	825	344350	825	381672	25.1	27.8
man1&2	5	90	13635	9,842	25.4	25.4	2285	283542	2285	315105	20.8	23.1	hig1&2	2	10	13750	34,940	90.1	90.1	901	345252	901	382573	25.1	27.8
hnp2	5	21	13656	12,701	25.8	31.8	541	284084	667	315771	20.8	23.1	hig1&2	3	20	13770	20,641	53.3	53.3	1065	346317	1065	383638	25.2	27.9
ala1&2	5	80	13736	10,047	25.9	25.9	2074	286157	2074	317845	20.8	23.1	hig1&2	4	18	13788	15,481	39.9	39.9	719	347036	719	384357	25.2	27.9
hun3	5	35	13771	10,057	25.9	25.9	908	287066	908	318753	20.8	23.1	hig1&2	5	10	13798	13,820	35.7	35.7	357	347392	357	384714	25.2	27.9
eti1&2	4	60	13831	10,104	26.1	26.1	1564	288630	1564	320317	20.9	23.2	hig3&4	2	14	13812	44,598	115.1	115.1	1611	349003	1611	386324	25.3	28.0
sba4	5	30	13861	11,797	26.2	33.7	786	289415	1012	321329	20.9	23.2	hig3&4	3	26	13838	24,520	63.3	63.3	1645	350648	1645	387969	25.3	28.0
hmb1&2	5	21	13882	13,521	27.4	33.8	576	289992	710	322039	20.9	23.2	hig3&4	4	30	13868	17,262	44.5	44.5	1336	351984	1336	389305	25.4	28.1
hnp3	5	21	13903	13,552	27.5	33.9	578	290570	711	322751	20.9	23.2	hig3&4	5	9	13877	15,100	39.0	39.0	351	352335	351	389656	25.4	28.1
eti1&2	5	64	13967	10,719	27.7	27.7	1770	292339	1770	324521	20.9	23.2	man1&2	5	90	13967	9,664	24.9	24.9	2244	354579	2244	391900	25.4	28.1

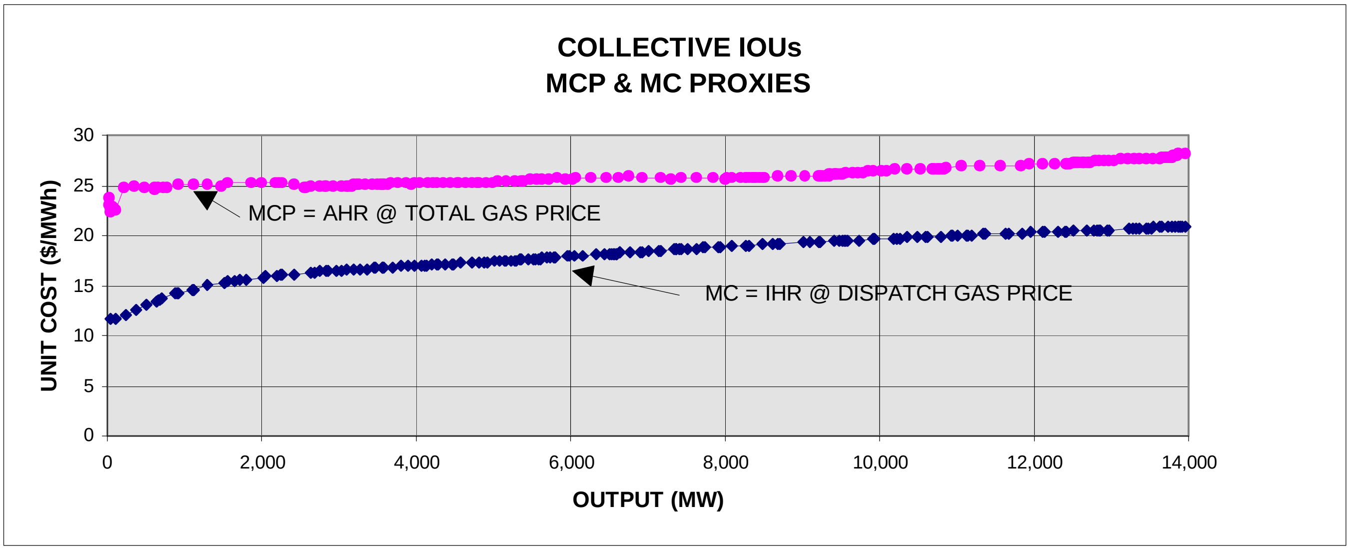

Figure C-8-ALL IOUs

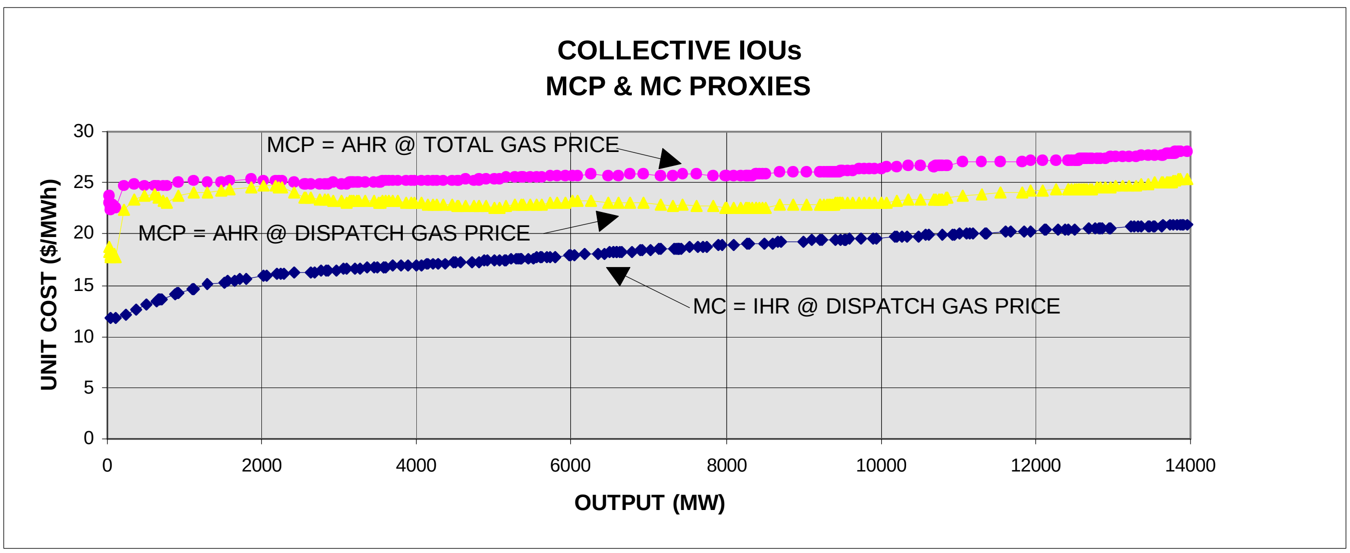

Figure C-9-ALL IOUs

RULE OF THUMB FORMULAS

This section describes the development of my Rule of Thumb (ROT) formulas for estimating the Marginal Cost (MC) and Market Clearing Price (MCP). These formulas can not be developed directly from the work in the previous section because that methodology masks the differences in gas prices between the Cool Water Units and the rest of the SCE units. We must return to our basic method and reconstruct it for this purpose.

The ***SIHRs*** and ***SAHR$_{AVE}$*** can be reconstructed in two ways. One way is to take all of the previously developed block ***IHRs*** and ***AHR$_{AVE}$*** data and sort it as we did in Tables C-5, but this time keeping the Cool Water and the other SCE units separate. This means that only Table C-5-SCE really needs to be redone. The last line in each Table provides the necessary system ***IHRs*** and ***AHR$_{AVE}$s, SIHRs*** and ***SAHR$_{AVE}$.***

The other method, which produces identical results, requires that we reconstruct the ***IHR*** and ***AHR$_{AVE}$*** data on a unit basis rather than a block basis. These ***IHRs*** and ***AHR$_{AVE}$*** can then be averaged into system values, ***SIHRs*** and ***SAHR$_{AVE}$***, for each IOU. These system IOU values can then be converted to a combined value representative of the WSCC system. I will now describe this procedure in more detail, first for the ***IHRs*** and then for the ***AHR$_{AVE}$*** values.

Since ***IHR*** is being integrated to find the average value, it will be given the name of ***IHR$_{AVE}$*** -- even though it probably warranted this nomenclature all along -- try not to get confused.

The Input-Output Curve (Btu/hr) can be represented by a third order equation:

$$Y=aX^3+bX^2+cX+d$$

Where: ***Y*** is the Input fuel (Btu/hr)
X is the Output generation (MW)

The Incremental Heat Rate curve (***IHR***) is equal to the first derivative of Input-Output curve:

$$IHR = dy/dx = 3aX^2+2bX+c$$

The average ***IHR, IHR$_{AVE}$***, is the integral of ***IHR*** from X_1 to X_2 divided by the quantity $X_2 - X_1$:

$$IHR_{AVE} = [\int IHR\ dx \ \{\text{from } X_1 \text{ to } X_2\}\ ]\ /\ (X_2 - X_1)$$

Where: X_1 = ***Minimum operating level of the unit (MW)***
X_2 = ***Maximum operating level of the unit (MW)***

The integration of ***IHR***, ($\int$ ***IHR dx***), is as follows:

$$\int IHR\ dx = \int [3aX^2+2bX+c]dx = aX^3+ b\cdot X^2+cX+d$$

If you were paying attention, you noted that this brought you right back to the Input-Output equation where you started.

The complete step-by-step process of calculating IHR_{AVE} is essentially identical to that provided at the beginning of this Appendix and will not be repeated here. The coefficients to complete these calculations are, of course, the same ones provided earlier in Table C-3.

The AHR_{AVE} is computed in a similar way, and is essentially the same as that shown at the beginning of this Appendix except that the integration takes place over the entire unit as follows:

Again, the Input-Output Curve (Btu/hr) can be represented by a third order equation:

$$Y=aX^3+bX^2+cX+d$$

Where: Y is the Input fuel (Btu/hr)
X is the Output generation (MW)

The Average Heat Rate curve (***AHR***) is equal to the Input-Output curve divided by the respective capacity, ***Y/X:***

$$AHR = Y/X = (aX^3+bX^2+cX+d)/X$$

The average ***AHR***, AHR_{AVE}, is the integral of ***AHR*** from X_1 to X_2 divided by the quantity $X_2 - X_1$:

$$AHR_{AVE} = [\int AHR\ dx_{\{from\ X_1\ to\ X_2\}}]\ /\ (X_2 - X_1)$$

Where: X_1 = ***Minimum operating level of the unit (MW)***
X_2 = ***Maximum operating level of the unit (MW)***

The integration of ***AHR***, ($\int$ ✌☝***R dx***), is as follows:

$$\int AHR\ dx = \int ☯(aX^3+bX^2+cX+d)/X]dx = a/3 \cdot X^3 + b/2 \cdot X^2 + c \cdot X + d \cdot ln(X)$$

Again, I do not show the step-by-step procedure as it is essentially the same as that shown at the beginning of the Appendix, and uses the same Table C-3 for the necessary coefficients.

The system IHR_{AVE}, $SIHR_{AVE}$,and system AHR_{AVE}, $SAHR_{AVE}$, are developed as weighted averages of the individual units, weighted again by the differential capacities. The calculations of which are shown in Tables C-9 and C-10, respectively.

TABLE C-9: SUMMARY OF *$SIHR_{AVE}$* CALCULATIONS

PG&E GENERATING UNITS

PLANT	X2-X1 (MW)	IHR (Btu/kWh)	(X2-X1)*IHR (1000Btu/hr)
Contra Costa 6	294	8,984	2,641,282
Contra Costa 7	294	8,941	2,628,575
Humboldt 1&2	95	11,428	1,085,660
Hunters Pt 2	97	11,536	1,118,946
Hunters Pt 3	97	11,728	1,137,589
Hunters Pt 4	264	9,323	2,461,248
Morro Bay 1&2	264	9,684	2,556,457
Morro Bay 3	292	9,098	2,656,473
Morro Bay 4	292	9,019	2,633,414
Moss Landing 6	689	8,283	5,707,305
Moss Landing 7	689	8,131	5,602,571
Pittsburg 1&2	264	9,482	2,503,173
Pittsburg 3&4	264	9,761	2,576,832
Pittsburg 5	279	9,066	2,529,380
Pittsburg 6	279	9,121	2,544,650
Pittsburg 7	600	8,825	5,295,276
Potrero 3	160	9,428	1,508,455
TOTAL	5213		47,187,286
SYSTEM		**9,052**	**Btu/kWh**

SCE GENERATING UNITS

PLANT	X2-X1 (MW)	IHR (Btu/kWh)	(X2-X1)*IHR (1000Btu/hr)
Alamitos 1&2	330	9,554	3,152,971
Alamitos 3&4	600	8,856	5,313,461
Alamitos 5&6	700	8,834	6,183,727
Cool Water 1	48	9,651	463,263
Cool Water 2	62	9,643	597,849
Cool Water 3&4	372	7,499	2,789,575
El Segundo 1&2	330	9,545	3,149,771
El Segundo 3&4	630	8,796	5,541,283
Etiwanda 1&2	244	9,941	2,425,699
Etiwanda 3&4	600	8,862	5,317,294
Higrove 1&2	58	8,454	490,328
Higrove 3&4	79	8,198	647,604
Huntington 1&2	390	8,926	3,481,230
Long Beach 8&9	490	9,712	4,758,745
Mandalay 1&2	390	9,065	3,535,500
Ormond Beach 1	500	8,620	4,309,800
Ormond Beach 2	700	8,684	6,079,045
Redondo 5&6	330	9,253	3,053,518
Redondo 7&8	700	8,896	6,227,059
San Bernardino 1&2	112	9,197	1,030,045
TOTAL	7665		68,547,765
SYSTEM		**8,943**	**Btu/kWh**
Cool Water		**7,989**	**Btu/kWh**
Rest of SCE		**9,007**	**Btu/kWh**

SDG&E GENERATING UNITS

PLANT	X2-X1 (MW)	IHR (Btu/kWh)	(X2-X1)*IHR (1000Btu/hr)
Encina 1	87	10,226	889,638
Encina 2	84	10,234	859,650
Encina 3	90	10,309	927,823
Encina 4	273	9,877	2,696,503
Encina 5	295	9,495	2,800,997
So. Bay 1	117	9,327	1,091,281
So. Bay 2	120	9,735	1,168,195
So. Bay 3	141	9,443	1,331,441
So. Bay 4	112	10,868	1,217,203
TOTAL	1319		12,982,730
SYSTEM		**9,843**	**Btu/kWh**

LEGEND

X2 = MAXIMUM CAPACITY
X1 = MINIMUM CAPACITY
IHR = IHRave

TABLE C-10: SUMMARY OF $SAHR_{AVE}$ CALCULATIONS

PG&E GENERATING UNITS

PLANT	X2-X1 (MW)	AHR (Btu/kWh)	(X2-X1)*AHR (1000Btu/hr)
Contra Costa 6	294	10,067	2,959,640
Contra Costa 7	294	10,142	2,981,717
Humboldt 1&2	95	13,255	1,259,178
Hunters Pt 2	97	13,502	1,309,667
Hunters Pt 3	97	13,244	1,284,700
Hunters Pt 4	264	10,264	2,709,702
Morro Bay 1&2	264	10,746	2,837,042
Morro Bay 3	292	10,368	3,027,375
Morro Bay 4	292	10,109	2,951,874
Moss Landing 6	689	10,215	7,038,181
Moss Landing 7	689	10,061	6,932,050
Pittsburg 1&2	264	11,071	2,922,771
Pittsburg 3&4	264	10,885	2,873,617
Pittsburg 5	279	10,350	2,887,650
Pittsburg 6	279	10,144	2,830,195
Pittsburg 7	600	10,540	6,323,833
Potrero 3	160	9,893	1,582,880
TOTAL	5213		54,712,072
SYSTEM		**10,495**	**Btu/kWh**

SCE GENERATING UNITS

PLANT	X2-X1 (MW)	AHR (Btu/kWh)	(X2-X1)*AHR (1000Btu/hr)
Alamitos 1&2	330	12,693	4,188,635
Alamitos 3&4	600	11,689	7,013,662
Alamitos 5&6	700	9,829	6,880,021
Cool Water 1	48	10,642	510,830
Cool Water 2	62	10,684	662,407
Cool Water 3&4	372	10,610	3,946,875
El Segundo 1&2	330	12,558	4,144,051
El Segundo 3&4	630	11,433	7,202,742
Etiwanda 1&2	244	12,760	3,113,552
Etiwanda 3&4	600	11,263	6,757,831
Higrove 1&2	58	20,329	1,179,064
Higrove 3&4	79	24,249	1,915,651
Huntington 1&2	390	10,621	4,142,197
Long Beach 8&9	490	10,524	5,156,643
Mandalay 1&2	390	10,416	4,062,294
Ormond Beach 1	500	9,737	4,868,332
Ormond Beach 2	700	10,598	7,418,625
Redondo 5&6	330	13,003	4,290,935
Redondo 7&8	700	9,936	6,955,540
San Bernardino 1&2	112	14,005	1,568,541
TOTAL	7665		85,978,428
SYSTEM		**11,217**	**Btu/kWh**
Cool Water		**10,623**	**Btu/kWh**
Rest of SCE		**11,257**	**Btu/kWh**

SDG&E GENERATING UNITS

PLANT	X2-X1 (MW)	AHR (Btu/kWh)	(X2-X1)*AHR (1000Btu/hr)
Encina 1	87	11,155	970,526
Encina 2	84	11,857	995,949
Encina 3	90	11,343	1,020,870
Encina 4	273	11,203	3,058,491
Encina 5	295	10,953	3,231,146
So. Bay 1	117	10,235	1,197,528
So. Bay 2	120	10,647	1,277,678
So. Bay 3	141	10,394	1,465,489
So. Bay 4	112	12,479	1,397,643
TOTAL	1319		14,615,320
SYSTEM		**11,081**	**Btu/kWh**

LEGEND

X2 = MAXIMUM CAPACITY
X1 = MINIMUM CAPACITY
AHR = AHRave

Table C-11 summarizes the Incremental Capacities and $\boldsymbol{SIHR_{AVE}}$ values of Table C-9 along with the Interim FR 97 dispatch gas prices. We can take this data and construct our ROT formulas.

TABLE C-11: SUMMARY OF $\boldsymbol{SIHR_{AVE}}$ DATA FROM TABLE C-9 AND GAS PRICE DATA

	INCR. CAPACITY	$SIHR_{AVE}$S	DISPATCH GAS PRICE
PG&E	5,213 MW	9,052 Btu/kWh	2.03 $/MMBtu
SCE	7,183 MW	9,007 Btu/kWh	2.58 $/MMBtu
Cool Water	482 MW	7,989 Btu/kWh	1.67 $/MMBtu
SDG&E	1,319 MW	9,843 Btu/kWh	2.22 $/MMBtu

The resulting formula for estimating the IOU MCs is simply the IOU ***SIHR*** times the IOU's dispatch gas price (**DGP**): $\mathbf{MC_{EST}} = \boldsymbol{SIHR} * \mathbf{DGP}$. The SCE calculation is the weighted average of the Cool Water units and the other SCE units.

- PG&E: $\mathbf{MC_{PG\&E}} = \boldsymbol{SIHR_{PG\&E}} * \mathbf{DGP_{PG\&E}}$ = 9,052*2.03 / 1000 = 18.4 $/MWh
- SCE: $\mathbf{MC_{SCE}} = \boldsymbol{SIHR_{SCE}} * \mathbf{DGP_{SCE}}$ = 9,007*2.58 / 1000 = 23.2 $/MWh
- Cool Water: $\mathbf{MC_{CW}} = \boldsymbol{SIHR_{CW}} * \mathbf{DGP_{CW}}$ = 7,989*1.67 / 1000 = 13.3 $/MWh
- SCE AVERAGE: $\mathbf{MC_{SCE+CW}}$ = (23.2 $/MWh*7183MW + 13.3 * 482MW)/7665 = 22.6 $/MWh
- SDG&E: $\mathbf{MC_{SDG\&E}} = \boldsymbol{SIHR_{SDG\&E}} * \mathbf{DGP_{SDG\&E}}$ = 9,843*2.22 / 1000 = 21.9 $/MWh

The system MC for the three IOUs is the average of the three weighted by the differential capacities (difference between the maximum and minimum capacity).

$$\mathbf{MC_{EST}} = (\mathbf{MW_{PG\&E}} * \mathbf{MC_{PG\&E}} + \mathbf{MW_{SCE}} * \mathbf{MC_{SCE}} + \mathbf{MW_{CW}} * \mathbf{MC_{CW}} + \mathbf{MW_{SDG\&E}} * \mathbf{MC_{SDG\&E}}) \,/\, (\mathbf{MW_{PG\&E}} + \mathbf{MW_{SCE}} + \mathbf{MW_{CW}} + \mathbf{MW_{SDG\&E}})$$

Where: **MW** = ⇙ Capacity differential for all units in the IOU

If these values in Table C-11 are now substituted into $\mathbf{MC_{EST}}$, the value of 21.0$/MWh results:

$$\mathbf{MC_{EST}} = (5,213*18.4 + 7,183*23.2 + 482*13.3 + 1,319*21.9) \,/\, (5,213 + 7,183 + 482 + 1,319)/1000 = 21.0 \text{ \$/MWh}$$

This equation can now be used for estimating the MC for small perturbations of gas price, by allowing all the values except the dispatch gas cost (DGP) could become constants as follows:

$$\mathbf{MC_{EST}} = (5213*9052*\mathbf{DGP_{PG\&E}} + 7183*9007*\mathbf{DGP_{SCE}} + 482*7989*\mathbf{DGP_{CW}} + 1319*9843*\mathbf{DGP_{SDG\&E}}) \,/\, (5,213 + 7,183 + 483 + 1,319)/1000$$

$$= (47,188,076*\mathbf{DGP_{PG\&E}} + 64,697,281*\mathbf{DGP_{SCE}} + 3,850,698*\mathbf{DGP_{CW}} + 12,982,917*\mathbf{DGP_{SDG\&E}}) \,/\, 14,197/1000$$

And, this can finally be further reduced to the following:

$\mathbf{MC_{EST}} = 3.32 * \mathbf{DGP_{PG\&E}} + 4.56 * \mathbf{DGP_{SCE}} + 0.27 * \mathbf{DGP_{CW}} + 0.92 * \mathbf{DGP_{SDG\&E}}$

An estimate for MCP can be developed similarly, using the data of Table C-10 and the total gas prices. This data is summarized in Table C-12 below.

TABLE C-12: SUMMARY OF $SAHR_{AVE}$ DATA FROM TABLE C-10 AND GAS PRICE DATA

	INCR. CAPACITY	$SAHR_{AVE}$	TOTAL GAS PRICE
PG&E	5,213 MW	10,495 Btu/kWh	2.50 $/MMBtu
SCE	7,183 MW	11,257 Btu/kWh	2.58 $/MMBtu
Cool Water	482 MW	10,623 Btu/kWh	2.11 $/MMBtu
SDG&E	1,319 MW	10,081 Btu/kWh	2.86 $/MMBtu

The resulting formula for estimating the IOU MCPs -- such as those found in a single-area Elfin run -- is simply the IOU $\boldsymbol{SAHR_{AVE}}$ times the IOU's total gas costs (**TGP**): $\mathbf{MCP_{EST}} = \boldsymbol{SAHR_{AVE}} * \mathbf{TGP}$. The SCE calculation is, as always, the weighted average of the Cool Water units and the other SCE units.

- PG&E: $\mathbf{MCP_{PG\&E}} = \boldsymbol{SAHR_{PG\&E}} * \mathbf{TGP_{PG\&E}} = 10{,}495*2.5/ 1000 = 26.2$ $/MWh
- SCE w/o Cool Water: $\mathbf{MCP_{SCE}} = \boldsymbol{SAHR_{SCE}} * \mathbf{TGP_{SCE}} = 11{,}257*2.58 / 1000 = 29.0$ $/MWh
- Cool Water: $\mathbf{MCP_{CW}} = \boldsymbol{SAHR_{CW}} * \mathbf{TGP_{CW}} = 10{,}623*2.11 / 1000 = 22.4$ $/MWh
- SCE AVERAGE: $\mathbf{MCP_{SCE+CW}} = (29.0*7184\text{MW} + 22.4*482\text{MW})/7665 = 28.6$ $/MWh
- SDG&E: $\mathbf{MCP_{SDG\&E}} = \boldsymbol{SAHR_{SDG\&E}} * \mathbf{TGP_{SDG\&E}} = 10{,}081*2.86 / 1000 = 31.7$ $/MWh

The system MC for the three IOUs is the average of the three weighted by the sum differential capacities (difference between the maximum and minimum capacity).

$$\mathbf{MCP_{EST}} = (\mathbf{MW_{PG\&E}} * \mathbf{MCP_{PG\&E}} + \mathbf{MW_{SCE}} * \mathbf{MCP_{SCE}} + \mathbf{MW_{CW}} * \mathbf{MCP_{CW}} + \mathbf{MW_{SDG\&E}} * \mathbf{MCP_{SDG\&E}}) / (\mathbf{MW_{PG\&E}} + \mathbf{MW_{SCE}} + \mathbf{MW_{CW}} + \mathbf{MW_{SDG\&E}})$$

Where: **MW** = ⇙ Capacity differential for each of the units in the IOU

If these values in the above table are now substituted into MCP_{EST} the value of 28.0 $/MWh results:

$$\mathbf{MCP_{EST}} = (5{,}213*26.2 + 7{,}183*29.0 + 482*22.4 + 1{,}319*31.7) / (5{,}213 + 7{,}183 + 482 + 1{,}319) = 28.0 \text{ \$/MWh}$$

It follows that this equation could be useful for estimating the MCP for small perturbations. For example, if it became necessary to quickly estimate the effect of various gas price forecasts, all the values except the gas price could become constants as follows:

$$\mathbf{MCP_{EST}} = (5213*10495* \mathbf{TGP_{PGE}} + 7183*11259* \mathbf{TGP_{SCE}} + 482*10623* \mathbf{TGP_{CW}} + 1319*11081* \mathbf{TGP_{SDG\&E}}) / (5{,}213 + 7{,}183 + 482 + 1{,}319)/1000$$

$$= (54{,}710{,}435*\mathbf{FC_{PGE}} + 80{,}859{,}031*\mathbf{FC_{SCE}} + 5{,}120{,}286*\mathbf{FC_{CW}} + 14{,}615{,}839* \mathbf{FC_{SDG\&E}}) / 14{,}197/1000$$

This equation can be further simplified to:

$\mathbf{MCP_{EST}} = 3.85^* \, \mathbf{TGP_{PG\&E}} + 5.70^* \, \mathbf{TGP_{SCE}} + 0.36^* \, \mathbf{TGP_{CW}} + 1.03^* \, \mathbf{TGP_{SDG\&E}}$

This equation can be graphically represented as shown in Figure C-10. The figure suggests that a 10 percent increase in either PG&E's or SCE's gas price will increase the MCP by about 5 percent, with SCE having the greater effect. SDG&E has relatively little effect on the MCP.

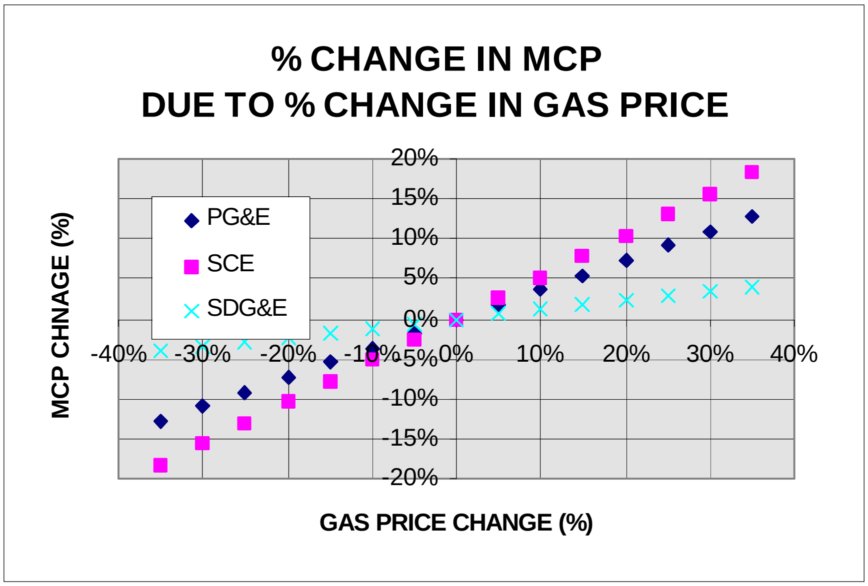

Figure C-10

Accuracy of the MC_{EST} and MCP_{EST} ROT Formulas

The $\mathbf{MC_{EST}}$ formula has been compared against various single-area Elfin runs and against multi-area UPLAN runs and is generally within about 3 percent. It can only be concluded that the non-economic restraints are balancing off the failure to capture the effect of non-firm power.

The $\mathbf{MCP_{EST}}$ seems to be effective in providing a rough estimate of the 1998 and 1999 MCPs. Compared to the UPLAN simulations it is within 3 percent both years.

One should be careful not to develop too much confidence in these formulas but they appear to be useful -- at least for the present set of assumptions.